ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 435

[FRL–5149–7]

RIN 2040–AB72

Effluent Limitations Guidelines, Pretreatment Standards, and New Source Performance Standards: Oil and Gas Extraction Point Source Category, Coastal Subcategory

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This proposed regulation would limit the discharge of pollutants into waters of the United States and the introduction of pollutants into publicly-owned treatment works by existing and new facilities in the coastal subcategory of the oil and gas extraction point source category.

This proposed regulation would establish effluent limitations guidelines and new source performance standards (NSPS) for direct dischargers based on ''best practicable control technology currently available'' (BPT), ''best conventional pollutant control technology'' (BCT), ''best available technology economically achievable'' (BAT), and ''best available demonstrated control technology'' (BADCT) for new sources. The proposal also would establish ''pretreatment standards for new sources'' (PSNS) and ''pretreatment standards for existing sources'' (PSES) for facilities discharging their wastewaters to publicly-owned treatment works (POTWs).

This regulation will reduce the discharge of pollutants into U.S. coastal water bodies by 4.3 billion pounds, thereby also reducing the impacts these discharges would otherwise incur to aquatic life and/or human health. As a result of consultation with stakeholders, the preamble solicits comments and data not only on issues raised by EPA, but also on those raised by State and local governments who will be implementing these regulations and by industry representatives who will be affected by them.

This proposal does not take into account the regulatory effects of the recently published final EPA Region VI NPDES General Permits for production facilities (January 9, 1995). With these permits in effect, the costs of this proposal will be reduced and the actual reduction of pollutant loadings to coastal waters would be approximately 71 percent less, or 1.25 billion pounds per year, due to today's proposal. EPA will more fully incorporate the regulatory effects of the Region VI General Permits upon promulgation of the final rule.

DATES: Comments on the proposal must be received by May 18, 1995. Two public meetings will be held during the comment period: on March 7, 1995, in New Orleans, Louisiana and on March 21, 1995, in Seattle, Washington. Both meetings will be held from 9:00 am to 12:00 pm.

ADDRESSES: Submit comments in writing to: Ms. Allison Wiedeman, Engineering and Analysis Division (4303), U.S. EPA, 401 M Street, S.W., Washington, DC 20460. Please submit any references cited in your comments. EPA would appreciate an original and two copies of your comments and enclosures (including references).

The public record supporting the proposed effluent limitations guidelines and standards is in the Water Docket located in the basement of the EPA Headquarters building, Room L102, 401 M Street S.W., Washington, DC 20460. For access to Docket materials call (202) 260–3027. The Docket staff requests that interested parties call, between 9:00 am and 3:30 pm, for an appointment before visiting the docket. The EPA regulations at 40 CFR Part 2 provide that a reasonable fee may be charged for copying.

The workshops covering the rulemaking will be held at the Minerals Management Service, Gulf of Mexico OCS Region, Office of the Regional Director, 1201 Elmwood Park Boulevard in New Orleans, Louisiana on March 7, 1995, and at the Federal Building, 915 2nd Avenue, North Auditorium in Seattle, Washington on March 21, 1995.

The background documents are available from the Office of Water Resource Center, RC–4100, at the U.S. EPA, Washington, DC address shown above; telephone (202) 260–7786 for the voice mail publication request line.

FOR FURTHER INFORMATION CONTACT: For technical information contact Ms. Allison Wiedeman at (202) 260–7179. For economic information contact Dr. Matthew Clark at (202) 260–7192.

SUPPLEMENTARY INFORMATION:

Public Meeting

No meeting materials will be distributed in advance of these meetings: all material will be distributed at the meetings. See **ADDRESSES** for information on location of the public meetings.

Docket

EPA notes that many documents in the record supporting these proposed rules have been claimed as confidential business information (CBI) and, therefore, are not included in the record that is available to the public in the Water Docket. To support the rulemaking, EPA is presenting certain information in aggregated form or is masking facility identities to preserve confidentiality claims. Further, the Agency has withheld from disclosure some data not claimed as confidential business information because release of this information could indirectly reveal information claimed to be confidential.

Some facility-specific data, which have been claimed as confidential business information, are available to the company that submitted the information. To ensure that all CBI is protected in accordance with EPA regulations, any requests for company-specific data should be submitted to EPA on company letterhead and signed by a responsible official authorized to receive such data. The request must list the specific data requested and include the following statement, ''I certify that EPA is authorized to transfer confidential business information submitted by my company, and that I am authorized to receive it.''

Overview

This preamble includes a description of the legal authority for these rules; a summary of the proposal; a description of the background documents that support these proposed regulations and other background information; and a description of the technical and economic methodologies used by EPA to develop these regulations. This preamble also solicits comment and data on specific areas of interest. The definitions, acronyms, and abbreviations used in this notice are defined in Appendix A to the preamble.

Organization of This Document

I. Legal Authority

These regulations are being proposed under the authority of sections 301, 304, 306, 307, 308, and 501 of the Clean Water Act (CWA), 33 U.S.C. sections 1311, 1314, 1316, 1317, 1318, and 1361.

II. Summary and Scope of the Proposed Regulations

A. Purpose of This Rulemaking

The purpose of this rulemaking is to propose effluent limitations guidelines and standards for the control of the discharge of pollutants for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. The discharge limitations proposed today apply to discharges from coastal oil and gas extraction facilities, including exploration, development and production operations. The processes and operations which comprise the coastal oil and gas subcategory (Standard Industrial Classification (SIC) Major Group 13) are currently regulated under 40 CFR Part 435, Subpart D. These regulations are being proposed under the authority of the CWA, as discussed in Section I of this notice. The regulations are also being proposed pursuant to a Consent Decree entered in *NRDC et al.* v. *Reilly,* (D D.C. No. 89–2980, January 31, 1992) and are consistent with EPA's latest Effluent Guidelines Plan under section 304(m) of the CWA. (See 59 FR 44234, August 26, 1994). The existing effluent limitations guidelines, which were issued on April 13, 1979 (44 FR 22069), are based on the achievement of best practicable control technology currently available (BPT). This proposed rule is referred to as the Coastal Guidelines throughout this preamble.

This summary section highlights key aspects of the proposed rule. The technology descriptions discussed later in this notice are presented in abbreviated form; more detailed descriptions are included in the Development Document for Proposed Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category, referred to hereafter as the ''Coastal Technical Development Document''. Today's proposal presents EPA's selected technology approach and several others that were considered in the regulation development process. The proposed rule is based on a detailed evaluation of data acquired during the development of the proposed limitations. As indicated below in the discussion of the specifics of the proposal, EPA welcomes comment on all options and issues and encourages commenters to submit additional data during the comment period. Also, EPA is willing to meet with interested parties during the comment period to ensure that EPA has the views of all parties and the best possible data upon which to base a decision for the final regulation. EPA emphasizes that it is soliciting comments on all options suggested in and raised by this proposal and that it may adopt any such options or combination of options in the final rule.

B. Summary of Proposed Coastal Guidelines

EPA proposes to establish regulations based on ''best practicable control technology currently available ''(BPT) for one specific wastestream for which BPT does not currently apply, and ''best conventional pollutant control technology'' (BCT), ''pretreatment standards for existing sources'' (PSES), ''best available technology economically achievable'' (BAT), best available demonstrated control technology (BADCT) for new sources, and ''pretreatment standards for new sources'' (PSNS) for the remaining waste streams.

Under this rule, EPA is co-proposing three options for the control of drilling fluids and cuttings (including any effluent from dewatering pit closures activities) for BAT effluent limitations guidelines, and NSPS. The three options considered contain zero discharge for all areas, except two of the options contain allowable discharges for Cook Inlet. One of these options, which would allow discharges meeting a more stringent toxicity limitation if selected for the final rule, would require an additional notice for public comment since the specific toxicity limitation has not been determined at this time. The three options are: Option 1—zero discharge of all areas except Cook Inlet where discharge limitations require toxicity of no less than 30,000 ppm (SPP), no discharge of free oil and diesel oil and no more than 1 mg/l mercury and 3 mg/l cadmium in the stock barite, Option 2—zero discharge for all areas except for Cook Inlet were discharge limitations would be the same as Option 1, except toxicity would be set to meet a limitation between 100,000 ppm (SPP) and 1 million ppm (SPP), and Option 3—zero discharge for all areas. EPA is proposing PSES and PSNS prohibiting all discharges of drilling fluids and drill cuttings. BCT for drilling fluids and cuttings is being proposed as zero discharge for the entire subcategory except for Cook Inlet, Alaska. BCT limitations for drilling fluids and cuttings for Cook Inlet would require no discharge of free oil (as determined by the static sheen test).

EPA is proposing to prohibit discharges of produced water from all coastal subcategory operations except those located in Cook Inlet, Alaska, under BAT. Proposed BAT for coastal facilities in Cook Inlet would limit the discharge of oil and grease in produced water to a daily maximum of 42 mg/l and a thirty day average of 29 mg/l. EPA is proposing to prohibit discharges of produced water from all coastal subcategory operations under NSPA, PSNS, and PSES. BCT limits for produced waters in all coastal regions (including Cook Inlet) would be set equal to the current BPT limitations, which limit the discharge of oil and grease to a daily maximum of 72 mg/l and a thirty day average of 48 mg/l.

BCT for treatment, workover and completion fluids is proposed to be set equal to current BPT limits prohibiting discharges of free oil, with compliance to be determined by use of the static sheen test. EPA is co-proposing two options for BAT and NSPS limitations for treatment, workover and completion finds. Option 1 would require no discharge of free oil and prohibit discharges to freshwaters of Texas and Louisiana. This option reflects current practice. Option 2 would require the same limitations as the preferred option for produced water. This option would require for BAT that discharges of treatment, workover and completion fluids would be prohibited in all coastal areas except Cook Inlet. In Cook Inlet, these discharges would be required to meet a daily maximum oil and grease limitation of 42 mg/l and a 30 day average of 29 mg/l. Option 2 would require zero discharge of these fluids everywhere for NSPS. EPA proposes zero discharge as PSES, and PSNS for treatment, workover and completion fluids.

BPT, BCT, BAT, NSPS, PSES and PSNS are being proposed for produced sand and would prohibit all discharges of this wastestream. The only BPT effluent limitations guidelines being proposed today are for produced sand which is the only wastestream for which BPT limits have not been previously promulgated.

BCT, BAT, and NSPS limits being proposed for deck drainage would be set equal to current BPT limits prohibiting discharges of free oil, with compliance to be determined by use of the visual sheen test. EPA is proposing zero discharge for PSES and PSNS for deck drainage because collection and capture of this wastestream is technically impractical in many situations (as discussed later in Section VI.D.) such that its direction to POTW's would rarely if ever occur. EPA also believes that combining this wastestream with municipal treatment facilities that may already be at full capacity should not be encouraged.

BCT is being proposed for domestic wastes as equal to BPT (which is no discharge of floating solids) with an additional requirement prohibiting the discharge of garbage. BAT is being proposed for domestic wastes to prohibit discharge of foam. NSPS is being proposed for domestic wastes as equal to BCT and no discharge of foam and no discharge of garbage. No pretreatment standards are being established for domestic wastes.

BCT and NSPS limitations for sanitary wastes are being proposed as equal to the current BPT effluent limitations guidelines. Sanitary waste effluents from facilities continuously manned by ten (10) or more persons would contain a minimum residual chlorine content of 1 mg/1, with the chlorine level maintained as close to this concentration as possible. Coastal facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons must comply with a prohibition on the discharge of floating solids. BAT is not being developed for sanitary wastes because no toxic or nonconventional pollutants of concern have been identified in this waste stream. No pretreatment standards are being established for sanitary wastes.

Compliance with these proposed limitations would result in a yearly decrease of 4.3 billion pounds of toxic, nonconventional and conventional pollutants in produced water, from zero to 23 million pounds of toxic nonconventional and conventional pollutants in drilling fluids and drill cuttings (depending on the option considered), and zero to 3.9 million pounds of toxic, nonconventional, and conventional pollutants in treatment, workover, and completion fluids (depending on the option considered).

EPA expects a variety of human health, and environmental benefits to result from these reductions in effluent loadings. In particular, the benefits include: Relief to coastal waters which support spawning grounds, nurseries and habitats for commercial and recreational fisheries: Reducing documented aquatic ''dead zone'' impacts; reduction of potential cancer risks to anglers from consuming seafood contaminated by produced water radionuclides; and reducing potential exposure of endangered species to toxic contaminants. This proposal will result in total benefits ranging from $3.2 to $230 million (in 1990 $'s) due to reduced cancer risks and increased recreational values of wetlands.

Since the inception of the project in 1994, there have been periodic meetings with the industry and several trade associations, including the Louisiana and Texas Independent Oil and Gas Associations (TIOGA and LIOGA) and American Petroleum Institute (API) to discuss progress on the rulemaking. The Agency also has met with the Natural Resources Defense Council (NRDC) to discuss progress on this rulemaking. Because all of the facilities affected by this proposal are direct discharges, the Agency did not conduct an outreach survey of POTWs.

The Agency also held a public meeting on July 19, 1994. The purpose of the meeting was to present the project status and discuss the technical options under consideration for this proposal. Representatives from industry trade associations, individual industry companies, state regulatory authorities, the U.S. Department of Energy and Interior (Minerals Management Service) and the Sierra Club Legal Defense Fund attended.

The Agency will continue this process of consulting with state, local, and other affected parties after proposal in order to further minimize the potential for unfunded mandates that may result from this rule. These proposed requirements, when promulgated, will be implemented via the existing regulatory structure and no additional burden is expected.

C. The EPA Region VI Coastal Oil and Gas Production NPDES General Permits

EPA's Region VI has recently published final NPDES General permits regulating produced water and produced sand discharges to coastal waters in Louisiana and Texas (60 FR 2387, Jan. 9, 1995). The permits prohibit the discharge of produced water and produced sand derived from the coastal subcategory to any water subject to EPA jurisdiction under the Clean Water Act.

Much of the industry covered by today's proposed rulemaking is also covered by these General permits. However, a significant difference between the permits and this proposal is that the permits do not cover produced water discharges derived from the Offshore subcategory wells into the main deltaic passes of the Mississippi River, or to the Atchafalaya River below Morgan City including Wax Lake Outlet. The rulemaking being proposed today would cover these discharges (see the discussion below entitled ''C. Preventing the Circumvention of Effluent Limitations Guidelines and New Source Performance Standards'').

Due to the close proximity of the timing of the publication of the Region 6 permits and this proposal, this preamble presents the costs and impacts of today's rulemaking as if the Region Vi

General permits were not final. As presented in later sections of this preamble, today's proposal (including the facilities covered by the Region VI permit) would remove 4.3 billion pounds of pollutants in produced water from being discharged per year. The Region VI permit covers approximately 71 percent of the produced water volume being discharged in the coastal subcategory. The remaining 29 percent is derived from coastal facilities treating offshore produced waters and currently discharging them into main deltaic river passes in Louisiana, as well as from other coastal operations in the U.S. Thus, with the Region VI General permits final, this rule would actually result in the removal of 1.25 billion pounds (29 percent of 4.3 billion pounds) of pollutants per year from being discharged into coastal waters.

As also presented in later sections of this preamble, compliance costs of today's rulemaking (including the facilities covered by the Region VI permit) total approximately $40.4 million annually. With the Region VI General permits final, the costs of this rule would be reduced to approximately $19.9 million annually.

EPA will more fully incorporate regulatory effects of the Region VI General permits upon promulgation of the final rule.

D. Preventing the Circumvention of Effluent Limitations Guidelines and New Source Performance Standards

This rule also proposes a provision intended to prevent oil and gas facilities subject to Part 435 of this title from circumventing the effluent limitations guidelines, new source performance standards and pretreatment standards applicable to those facilities by moving effluent from one subcategory to another subcategory. When EPA establishes its effluent limitations guidelines and standards, it does so based on a determination, supported by analyses contained in the rulemaking record, that facilities in that subcategory, among other factors also considered under the CWA, can technologically and economically achieve the requirements of the rule. The purpose of the rule is not accomplished if facilities move effluent from a subcategory with more stringent requirements to a subcategory with less stringent requirements or if facilities move effluent from a subcategory with less stringent requirements to a subcategory with more stringent requirements and discharge effluent at the less stringent limitations. Until now, EPA has attempted to prevent this circumvention in the National Pollution Discharge Elimination System (NPDES) permits issued for this industry. EPA believes, however, that it would enhance the enforcement of these provisions to include them as part of the effluent limitations guidelines, new source performance standards and pretreatment standards.

Therefore, this rule proposes to prohibit oil and gas facilities from moving effluent from a subcategory with more stringent requirements to a subcategory with less stringent requirements, unless that effluent is discharged in compliance with the limitations imposed by the more stringent subcategory. For example, facilities could not move produced water generated from the onshore subcategory of the oil and gas industry (which is subject to zero discharge requirements) to the offshore subcategory of the oil and gas industry and dispose of the effluent at the offshore limitations and standards. Similarly, this rule proposes to prohibit facilities from moving produced water generated from the offshore subcategory to the coastal or onshore subcategory and discharging the produced water at the offshore limitations. (An offshore oil and gas facility could, however, pipe produced water to shore for treatment and return it to offshore waters for disposal at the offshore limits. Disposal of such produced water onshore however, would be subject to zero discharge.) EPA intends that these provisions would be applied prospectively in future NPDES permits.

E. Common Sense Initiative

On August 19, 1994, the Administrator established the Common Sense Initiative (CSI) Council in accordance with the Federal Advisory Committee Act (U.S.C. Appendix 2, Section 9 (c)) requirements. A principal goal of the CSI includes developing recommendations for optimal approaches to multimedia controls for industrial sectors including Petroleum Refining, Metal Plating and Finishing, Printing, Electronics and Computers, Auto Manufacturing, and Iron and Steel Manufacturing. The following are the six overall objectives of the CSI program, as stated in the ''Advisory Committee Charter.''

- Regulation. Review existing regulations for opportunities to get better environmental results at less cost. Improve new rules through increased coordination.
- Pollution Prevention. Actively promote pollution prevention as the standard business practice and a central ethic of environmental protection.
- Recordkeeping and Reporting. Make it easier to provide, use, and publicly disseminate relevant pollution and environmental information.
- Compliance and Enforcement. Find innovative ways to assist companies that seek to comply and exceed legal requirements while consistently enforcing the law for those that do not achieve compliance.
- Permitting. Improve permitting so that it works more efficiently, encourages innovation, and creates more opportunities for public participation.
- Environmental Technology. Give industry the incentives and flexibility to develop innovative technologies that meet and exceed environmental standards while cutting costs.

The coastal oil and gas extraction rulemaking effort was not among those included in the Common Sense Initiative. However, many oil and gas producers (mostly large companies) involved in coastal oil and gas extraction activities also have refineries. These companies are projected to incur costs associated with the requirements contained in this proposal, however, these costs are not projected to have an economic impact at the firm level. The Agency believes that the CSI objectives already have been incorporated into the coastal oil and gas extraction industry rulemaking, and the Agency intends to continue to pursue these objectives. The Agency particularly will focus on avenues for giving state and local authorities flexibility in implementing this rule, and giving the industry flexibility to develop innovative and costs effective compliance strategies. In developing this rule, EPA took advantage of several opportunities to gain the involvement of various stakeholders. Sections III. E, V and X of this preamble describe consultations with state and local governments and other parties including the industry. EPA has internally coordinated among relevant program offices in developing this rule as well. Section XIV describes related rulemakings that are being developed by EPA's Office of Air Quality, Planning and Standards, Underground Injection Control Program, and Spill Prevention, Control and Countermeasure Program. EPA will be monitoring these related rulemakings to assess their collective costs to the industry. Section VIII of the preamble describes the non-water quality impacts this proposed rule would have on other media including air emissions and solid waste disposal.

III. Background

A. Clean Water Act

1. Statutory Requirements of Regulations

The objective of the Clean Water Act (CWA) is to ''restore and maintain the chemical, physical, and biological integrity of the Nation's waters''. CWA § 101(a). To assist in achieving this objective, EPA issues effluent limitation guidelines, pretreatment standards, and new source performance standards for industrial dischargers. These guidelines and standards are summarized below:

a. Best Practicable Control Technology Currently Available (BPT)—Sec. 304(b)(1) of the CWA

BPT effluent limitations guidelines apply to discharges of conventional, priority, and non-conventional pollutants from existing sources. BPT guidelines are generally based on the average of the best existing performance by plants in a category or subcategory. In establishing BPT, EPA considers the cost of achieving effluent reductions in relation to the effluent reduction benefits, the age of equipment and facilities, the processes employed, process changes required, engineering aspects of the control technologies, non-water quality environmental impacts (including energy requirements), and other factors as the EPA Administrator deems appropriate. CWA § 304(b)(1)(B). Where existing performance is uniformly inadequate, BPT may be transferred from a different subcategory or category.

b. Best Conventional Pollutant Control Technology (BCT)—Sec. 304(b)(4) of the CWA

The 1977 amendments to the CWA established BCT as an additional level of control for discharges of conventional pollutants from existing industrial point sources. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that BCT limitations be established in light of a two part ''cost-reasonableness'' test. EPA published a methodology for the development of BCT limitations which became effective August 22, 1986 (51 FR 24974, July 9, 1986).

Section 304(a)(4) designates the following as conventional pollutants: biochemical oxygen demanding pollutants (measured as BOD_5), total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 FR 44501).

c. Best Available Technology Economically Achievable (BAT)—Sec. 304(b)(2) of the CWA

In general, BAT effluent limitations guidelines represent the best existing economically achievable performance of plants in the industrial subcategory or category. The CWA establishes BAT as a principal national means of controlling the direct discharge of toxic and nonconventional pollutants. The factors considered in assessing BAT include the age of equipment and facilities involved, the process employed, potential process changes, non-water quality environmental impacts, including energy requirements, and such factors as the Administrator deems appropriate. The Agency retains considerable discretion in assigning the weight to be accorded these factors. An additional statutory factor considered in setting BAT is economic achievability across the subcategory. Generally, the achievability is determined on the basis of total costs to the industrial subcategory and their effect on the overall industry financial health. As with BPT, where existing performance is uniformly inadequate, BAT may be transferred from a different subcategory or category. BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice.

d. Best Available Demonstrated Control Technology For New Sources (BADCT)—Section 306 of the CWA

NSPS are based on the best available demonstrated treatment technology and apply to all pollutants (conventional, nonconventional, and toxic). New plants have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. Under NSPS, EPA is to consider the best demonstrated process changes, in-plant controls, and end-of-process control and treatment technologies that reduce pollution to the maximum extent feasible. In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.

e. Pretreatment Standards for Existing Sources (PSES)—Sec. 307(b) of the CWA

PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of publicly-owned treatment works (POTW). The CWA authorizes EPA to establish pretreatment standards for pollutants that pass through POTWs or interfere with treatment processes or sludge disposal methods at POTWs. Pretreatment standards are technology-based and analogous to BAT effluent limitations guidelines.

The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR Part 403. Those regulations contain a definition of pass-through that addresses localized rather than national instances of pass-through and establish pretreatment standards that apply to all non-domestic dischargers. See 52 FR 1586, January 14, 1987.

f. Pretreatment Standards for New Sources (PSNS)—Sec. 307(b) of the CWA

Like PSES, PSNS are designed to prevent the discharges of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. PSNS are to be issued at the same time as NSPS. New indirect dischargers have the opportunity to incorporate into their plants the best available demonstrated technologies. The Agency considers the same factors in promulgating PSNS as it considers in promulgating NSPS.

g. Best Management Practices (BMPs)

Section 304(e) of the CWA gives the Administrator the authority to publish regulations, in addition to the effluent limitations guidelines and standards listed above, to control plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage which the Administrator determines may contribute significant amounts of pollutants.

h. CWA Section 304(m) Requirements

Section 304(m) of the CWA requires EPA to establish schedules for (i) reviewing and revising existing effluent limitations guidelines and standards and (ii) promulgating new effluent guidelines. On January 2, 1990, EPA published an Effluent Guidelines Plan (55 FR 80), in which schedules were established for developing new and revised guidelines for several industry categories, including the coastal oil and gas industry. Natural Resources Defense Council, Inc., challenged the Effluent Guidelines Plan in a suit filed in the U.S. District Court for the District of Columbia, (NRDC *et al* v. Reilly, Civ. No. 89–2980). On January 31, 1992, the Court entered a consent decree (the ''304(m) Decree''), which establishes schedules for, among other things, EPA's proposal and promulgation of effluent guidelines for a number of point source categories, including the Coastal Oil and Gas Industry. The most recent Effluent Guidelines Plan was published in the Federal Register on August 26, 1994 (59 FR 44234). This plan requires, among other things, that EPA propose the Coastal Guidelines by January 1995 and promulgate the Guidelines by July 1996.

2. Prior Federal Rulemakings and Other Notices

Coastal subcategory effluent limitations were proposed on October 13, 1976 (41 FR 44943). On April 13, 1979 (44 FR 22069) BPT effluent limitations guidelines were promulgated for all subcategories under the oil and gas category, but action on the BAT and NSPS regulations was deferred. Table 1 presents the 1979 BPT limitations.

TABLE 1.—COASTAL SUBCATEGORY BPT EFFLUENT LIMITATIONS [2]

Waste stream	Parameter	BPT effluent limitation
Produced Water	Oil and Grease	72 mg/l Daily Maximum 48 mg/l 30-Day Average.
Drilling Cuttings	Free Oil [1]	No Discharge.
Drilling Fluids	Free Oil [1]	No Discharge.
Well Treatment Fluids	Free Oil [1]	No Discharge.
Deck Drainage	Free Oil [1]	No Discharge.
Sanitary-M10	Residual Chlorine	1 mg/l (minimum).
Sanitary-M91M	Floating Solids	No Discharge.
Domestic Wastes	Floating Solids	No Discharge.

[1] The free oil ''no discharge'' limitation is implemented by requiring no oil sheen to be present upon discharge (visual sheen).
[2] 40 CFR Part 435, Subpart D.

On November 8, 1989, EPA published a notice of information and request for comments on the Coastal Oil and Gas subcategory effluent limitations guidelines development (54 FR 46919). The notice presented information known to date about control and treatment technologies, applicable to oil and gas wastes as well as the Agency's anticipated approach to effluent limitations guidelines development for BAT, BCT, and NSPS. It also solicited comments on the information presented as well as the limitations development approach and requested additional information where available.

B. Pollution Prevention Act

In the Pollution Prevention Act of 1990 (PPA) (42 U.S.C. 13101 *et seq.*, Pub. L. 101–508, November 5, 1990), Congress declared pollution prevention the national policy of the United States. The PPA declares that pollution should be prevented or reduced whenever feasible; pollution that cannot be prevented or reduced should be recycled or reused in an environmentally safe manner wherever feasible; pollution that cannot be recycled should be treated in an environmentally safe manner wherever feasible; and disposal or release into the environment should be chosen only as a last resort.

Today's proposed rules are consistent with this policy. In fact, for the two major wastestreams generated by this industry, EPA is proposing zero discharge for drilling fluids and cuttings, as well as zero discharge for approximately 80 percent of the volume of produced water. Zero discharge of wastes is an alternative that prevents pollution to the maximum extent possible. As described later in this notice, development of these proposed rules focused on pollution-preventing technologies, such as drilling fluids closed-loop recycle systems and produced water injection systems, that some segments of the industry have already adopted.

C. Coastal Subcategory Definition

The coastal oil and gas regulations at 40 CFR 435.41(e) currently define the coastal subcategory as follows:

''(1) any body of water landward of the territorial seas as defined in 40 CFR 125.1(gg) or (2) any wetlands adjacent to such waters.'' Part 125 was revised at 44 FR 32948 (June 7, 1979).

EPA proposes to clarify the ''coastal'' definition in this rule. First, EPA intends to revise the regulation to state that the coastal subcategory would consist of ''any oil and gas facility located in or on a water of the United States landward of the territorial seas.'' As suggested by the preamble to the 1979 guidelines in discussing the coastal definition (44 FR 22017; April 13, 1979), EPA intended the subcategory to cover all facilities located over waters under CWA jurisdiction, including adjacent wetlands. Courts have made it clear that isolated wetlands with an interstate commerce connection, as well as adjacent wetlands, are waters of the United States subject to CWA jurisdiction. *See, e.g., Hoffman Homes, Inc.* v. *Administrator* 999 F.2d 256 (7th Cir. 1993). The revised definition would make it clear that facilities located in or on isolated wetlands would be considered to be coastal. This application of the coastal definition is consistent with the EPA Region 6 final general permit for coastal drilling operations. 58 FR 49126 (September 21, 1993).

In addition, the revised definition would no longer refer to 40 CFR 125.1(gg). Part 125 was revised at 44 FR 32948 (June 7, 1979) and no longer exists in the CFR. That provision, when it did exist, merely cited section 502(8) of the CWA which defines territorial seas as ''the belt of seas measured from the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters, and extending seaward a distance of three miles.'' 40 CFR 125.1(gg) (July 1, 1978). That statutory definition is still in effect.

Also, EPA would explicitly include in the definition of ''coastal'' certain wells located in the area between the Chapman line and the inner boundary of the territorial seas that were determined to be coastal as a result of a decision of the U.S. Court of Appeals for the Fifth Circuit. *American Petroleum Institute* v. *EPA*, 661 F.2d 340 (5th Cir. 1981). The Chapman line is formed by a series of 40 latitude and longitude coordinates that roughly parallel the Louisiana and Texas coastline to the Mexican border. EPA's interim final regulations issued in 1976 (41 FR 44942; October 13, 1976) defined ''coastal'' to include all land and water areas landward of the inner boundary of the territorial seas and eastward of the point defined by 89 degrees 45 minutes West Longitude and 29 degrees 46 minutes North latitude and continuing west of that point through the series of longitude and latitude coordinates (the Chapman Line) to the point 97 degrees 19 minutes West Longitude and continuing southward to the U.S.-Mexican border.) So defined, the coastal area included areas on the Gulf coast of Texas and Louisiana. The 1976 boundaries were set to include wells located in both water and on land within the geographic area defined as coastal.

On April 13, 1979 (44 FR 22069), EPA redefined the coastal subcategory as set forth at 40 CFR 435.41(e). This new definition eliminated reference to the Chapman line, and instead, defined coastal with respect to a well's location over water bodies or wetlands. Under this definition, certain wells located on land, but discharging to coastal areas, were reclassified into the onshore subcategory and others were reclassified as stripper wells, depending on their production rate. The wells that were classified as onshore were required to meet zero discharge which is the standard applicable to onshore facilities. Industry challenged EPA's 1979 final rule. In *American Petroleum Institute* v. *EPA*, 661 F.2d 340, 354-57 (5th Cir., 1981), the Court held that EPA had failed to consider adequately the cost to the reclassified facilities of this regulatory change. As a result of the Court's decision, EPA suspended the applicability of the onshore subcategory guidelines (40 CFR 435.30) to the reclassified wells and to any wells that came into existence in the affected area after the issuance of the 1979 redefinition. See 47 FR 31554 (July 21, 1982). Thus, the wells affected by this suspension are classified as coastal. To reflect this fact, the definition of coastal in 40 CFR 453.41(e) would be revised to include facilities subject to the suspension.

D. New Source Definition

The definition of ''new source'' as it applies to the Offshore Guidelines was discussed at length in EPA's 1985 proposal, (50 FR 34617-34619, August 26, 1985) and in EPA's final rule (58 FR 12456-12458, March 4, 1993). EPA proposes that this definition would also apply to the coastal oil and gas industry. As discussed in the 1985 proposal and 1993 final rule, provisions in the NPDES regulations define new source (40 CFR 122.2) and establish criteria for a new source determination (40 CFR 122.29(b)). EPA is proposing special definitions which are consistent with 40 CFR 122.29 and which provide that 40 CFR 122.2 and 122.29(b) shall apply ''except as otherwise provided in an applicable new source performance standard.'' (See 49 FR 38046, Sept. 26, 1984.)

In summary, for coastal operations a drilling operation would be a new source if the drilling rig is drilling a coastal development well (not an exploratory well) in a new water area. Exploratory or development well drilling from an existing platform or rig that has not moved since it drilled a previously existing well would not be a new source. For production, a new source would be a facility discharging from a new site.

EPA invites comments on the definition of new sources as it applies to the coastal oil and gas subcategory.

E. Summary of Public Participation

EPA encourages full public participation in developing the final Coastal Guidelines. During the data gathering activities that preceded development of the proposed rule, EPA received written comments on the 1989 Notice of Information and Request for Comments and has met with representatives from industry and environmental groups, as well as state and other federal agencies. To further public participation on this rule, on July 19, 1994, EPA held a public meeting about the content and the status of the proposed regulation. The meeting was announced in the **Federal Register** (59 FR 31186; June 17, 1994), and information packages were distributed at the meeting. The public meeting also gave interested parties an opportunity to provide information, data, and ideas to EPA on key issues. EPA will assess all comments and data received at that public meeting along with comments and data received as a result of this proposal as well as the 1989 Notice of Information, prior to promulgation.

During the development of the proposed Coastal Guidelines, EPA sent a questionnaire to industry under authority of section 308 of the CWA. During its design, EPA met with industry trade associations (on March 19, 1992) to discuss its plans to issue a questionnaire. Following the March meeting, EPA distributed a draft of the questionnaire to NRDC, industry representatives, and trade associations for review and comment. On May 7, 1992, EPA met with industry representatives to discuss industry comments. NRDC did not provide comments. A final questionnaire was subsequently completed, reviewed and approved by the Office of Management and Budget (OMB) and sent to coastal oil and gas operators on August 30, 1993.

IV. Description of the Industry

A. Industry Description

Drilling in coastal areas occurs onland as well as over water or wetlands. Drilling occurs in two phases: Exploration and development. Exploration activities are those operations involving the drilling of wells to locate hydrocarbon bearing formations and to determine the size, and production potential of hydrocarbon reserves. Development activities involve the drilling of production wells once a hydrocarbon reserve has been discovered and delineated.

Drilling for oil and gas is generally performed by rotary drilling methods which involve the use of a circularly rotating drill bit that grinds through the earth's crust as it descends. Drilling fluids are injected down through the drill bit via a pipe that is connected to the bit, and serve to cool and lubricate the bit during drilling. The rock chips that are generated as the bit drills through the earth are termed drill cuttings. The drilling fluid also serves to transport the drill cuttings back up to the surface through the space between the drill pipe and the well wall (this space is termed the annulus), in addition to controlling downhole pressure.

As drilling progresses, large pipes called ''casing'' are inserted into the well to line the well wall. Drilling continues until the hydrocarbon bearing formations are encountered. In coastal areas, wells depths range from approximately 8,000–12,000 feet deep, and it takes approximately 20–60 days to complete drilling.

On the surface, the drilling fluid and drill cuttings undergo an extensive separation process to remove as much solids (e.g., cuttings) from the fluid as possible. The fluid is then recycled into the system, and the cuttings become a waste product. Intermittently during drilling, and at the end of the drilling process, drilling fluids may become wastes if they can no longer be reused or recycled.

Once the target formations have been reached, and a determination made as to which have commercial potential, the well is made ready for production by a process termed ''completion''. Completion involves cleaning the well to remove drilling fluids and debris, the perforation of the casing that lines the producing formation, insertion of production tubing to transport the hydrocarbon fluids to the surface, and installation of the surface wellhead. The well is now ready for production, or actual extraction of hydrocarbons.

The hydrocarbons extracted from the well usually consist of a combination of oil, gas, and brines (produced water). These fluids are initially directed from the wellhead to a separation facility where gas and oil are separated out and either treated further or sent directly offsite for sales, and the produced waters undergo further separation to remove as much oil as possible from the water.

The separation facilities, or production facilities, consist of the treatment equipment and storage tanks that process the produced fluids. Production facilities may be configured to service one well, or as central facilities which service multiple satellite wells, also known as tank batteries or gathering centers.

Coastal production facilities can be located over water or on land. Production facilities located over water exist in generally two types of configurations: (1) Individual deep water multi-well platforms or; (2) central facilities supported on barges or wooden or concrete pilings that service multiple satellite wells in shallow water. Production facilities on land may service satellite wells in any combination of locations. The type of configuration is an important factor when examining costs of installing pollution control equipment.

Multi-well platforms, such as those found in the Gulf of Mexico offshore region, are not commonly found in the coastal region of the Gulf of Mexico. Based on an earlier mapping effort of all oil and gas wells, EPA determined that there are only four structures owned and operated by four different operators in the coastal Gulf of Mexico region that can be classified as multi-well platforms. However in the Gulf coastal areas, many single wellheads are located throughout the coastal waters, serviced by gathering centers located on-land or on platforms. Although there are some exceptions, in most cases those located on land can be accessed by car or truck (land-access) while those facilities located over water must be accessed by boat or barge (water-access). An analysis of the EPA 1993 Coastal Oil and Gas Questionnaire data results indicates that approximately 34 percent of the production facilities in the Gulf of Mexico are land accessed, and 66 percent are water-accessed facilities. (See Section V.B for description of the Questionnaire). This distinction is important when estimating regulatory compliance costs and impacts as described in sections VI and VIII. On the other hand, all coastal structures in Cook Inlet, Alaska are deep water multi-well platforms, all accessible only by water (or air) transportation.

Depending on operational preference or regulatory requirements, many of the coastal production facilities do not discharge produced water and thus, would not incur costs due to this rulemaking.

B. Location

Coastal oil and gas activities are located on water bodies inland of the inner boundary of the territorial seas. These water bodies include inland lakes, bays and sounds, as well as saline, brackish, and freshwater wetland areas. Although the definition includes water bodies even in all inland U.S. states, EPA knows of no existing operations other than those in certain states bordering the coast. Thus, at this time, the coastal oil and gas operations are located only in coastal states.

Current coastal oil and gas activity exists along the Gulf of Mexico coastal states of Texas, Louisiana, Alabama and Florida, in San Pedro Bay, California and also in Alaska's Cook Inlet and the North Slope areas. The majority of Gulf Coast activity takes place in Texas and Louisiana. There, coastal oil and gas operations exist in a number of topographical situations including bays, sounds, lakes, and wetlands. Coastal oil and gas activity in Alabama is located in Mobile Bay; and a small number of wells are also located in wetlands along the west coast of Florida.

Coastal oil and gas activity in California exists behind the barrier island that forms San Pedro Bay (in Long Beach Harbor). There, four man-made islands have been constructed solely for the purpose of oil and gas extraction.

Roughly one third of all the coastal oil and gas production activity exists in Alaska. Deep water platforms exist in the northern part of Cook Inlet. In addition, operations resembling onshore activities (as opposed to deep water platforms) are located on the tundra wetlands of Alaska's North Slope.

C. Activity

Table 2 summarizes the number of producing wells and annual drilling activities for the coastal subcategory and the number of producing facilities that would incur costs (those still discharging after the projected final date of July 1996) due to this rulemaking, by geographic locations.

TABLE 2.—PROFILE OF COASTAL OIL AND GAS INDUSTRY

Coastal location	Region	Number of producing wells (1992)	Number of production facilities (1992)	Number of production facilities that would incur costs under this rule	Annual drilling activity	Number of operators that would incur costs under this rule
Gulf of Mexico	TX & LA	4675	853	216	686	122
	AL, FL	56	ND [1]	0	7	0
Alaska	Cook Inlet	237	8	8	8	5
	North Slope	2085	12	0	161	0
California	Long Beach Harbor	586	4	0	7	0
Total		7639	877	224	869	127

[1] Not determined.

Eight hundred and seventy seven (877) production facilities listed in Table 1 are currently discharging produced water in the coastal areas of Texas (TX), saline and brackish coastal waters of Louisiana (LA), and the Cook Inlet of Alaska. All coastal production facilities in Mississippi (MS), Alabama (AL), Florida (FL), the North Slope, and California do not discharge treated produced water, but rather inject it either for disposal or for waterflooding.

There are no discharges of drilling fluids and cuttings from coastal operators except for those in Cook Inlet. The volumes and locations of discharges are discussed in more detail in Section VI. By July 1996, the scheduled date for promulgation of this rule, EPA estimates that there will be 216 facilities operated by 122 operators discharging produced water. This is based on data obtained directly from industry, the 1993 Coastal Oil and Gas Questionnaire, and state permit records.

D. Waste Streams

The primary wastewater sources from the exploration and development phases of the coastal oil and gas extraction industry include the following:

- Drilling fluids.
- Drill cuttings.
- Sanitary wastes.
- Deck drainage.
- Domestic wastes.

The primary wastewater sources from the production phase of the industry include the following:

- Produced water.
- Produced sand.
- Well treatment, workover, and completion fluids.
- Deck drainage.
- Domestic wastes.
- Sanitary wastes.

Drilling fluids and drill cuttings are the most significant waste streams from exploratory and development operations in terms of volume and pollutants. Produced water is the largest waste stream from production activities in terms of volumes of discharged and quantity of pollutants. Deck drainage, sanitary wastes, domestic wastes, produced sand, and well treatment, completion, and workover fluids are often classified under the term miscellaneous wastes.

A summary of the sources and characteristics of each of these wastes is presented in Section VI of this notice. Detailed discussions of the origins and characteristics of the waste water effluents from exploration, development, and production are included in the Coastal Technical Development Document. EPA has primarily focused data gathering efforts and data analyses on drilling fluids, drill cuttings, and produced water due to their volumes and potential toxicity. Information on the other waste streams discussed above is more limited. Their volumes are generally smaller, and in most cases are either infrequently discharged or are commingled with the major waste streams. However, EPA has determined that it is appropriate to propose regulations for these wastes as well.

E. Current NPDES Permits

Discharges from coastal oil and gas operations in the Gulf of Mexico, California, and Alaska are regulated by general and individual NPDES permits based on BPT, State Water Quality Standards, and on Best Professional Judgment (BPJ) of BCT and BAT levels of control. Table 3 lists the requirements in these permits.

EPA's Region VI has developed general NPDES permits for each phase of oil and gas operations (drilling and production). The drilling permits for Louisiana and Texas were proposed in 1990 and a final permits published on September 21, 1993 (58 FR 49126). Region VI proposed general production permits on December 22, 1992 (57 FR 60926), and final permits on January 9, 1995 (60 FR 2387).

EPA's Region X issued a BPT and BPJ general NPDES permit for oil and gas operations in the Upper Cook Inlet. However, although expired, conditions of this general permit are still fully effective and enforceable until the permit is reissued. Region X is currently in the process of reissuing the BPT and BPJ/BAT general permit for this area with proposal expected in early 1995. In addition to the general permit, the Region issued an individual permit regulating discharges from exploratory drilling operations in Upper Cook Inlet in May 1993. The individual permit was also based on BPT and BPJ/BAT.

The State of Alabama, which has been authorized to administer the NPDES program, has also issued a final NPDES general permit covering facilities in state waters, including offshore and coastal facilities (including Mobile Bay). (Permit #ALG280000, May 25, 1994). This permit specifically prohibits the discharge of drilling fluids and cuttings, and produced water. The permit also does not allow the discharge of produced sands or treatment, workover and completion fluids.

Regional permit requirements are based on other factors, in addition to technology pollutant removal performance, including water quality criteria.

TABLE 3.—NPDES PERMIT REQUIREMENTS [1]

[Regional Permit Requirements]

Wastestream	Region X (CI 1986 BPT permit)	Region X exploration permit (1993)	Region VI final drilling permit (1993)	Region VI production permit (final) (1995)	Region IV permit (1994)
Produced Water	Monitor daily flow rate Oil & Grease: Phillips A Platform 20 mg/l daily max 15 mg/l mo. ave. Other facilities: 48/72 mg/l pH=6-9.	Not applicable	Covered in Production Permit.	No Discharge	No Discharge.
Produced Sand	No free oil (Static Sheen)	Not applicable	Not applicable	No Discharge	No Discharge.
Drilling Fluids and Cuttings.	(1) Toxicity: Discharge only approved generic muds.	(1) Flowrate = 750 bbl/hr	No Discharge	Not applicable.	No Discharge.
	(2) No free oil- static sheen	(2) Use authorized muds only.			
	(3) No discharge oil-based muds.	(3) Toxicity: 30,000 ppm in SPP.			
	(4) 10 percent oil content for cuttings.	(4) No free oil.			
	(5) No diesel oil	(5) No discharge of oil-based fluids.			
	(6) 1/3 mg/kg Hg/Cd in dry barite.	(6) 5 percent (wt) oil content in cuttings.			
	(7) Flow rate >40m = 1000 bbl/hr	(7) No discharge of diesel oil.			
		(8) 1 mg/kg Hg and 3 mg/kg Cd in stock barite.			

TABLE 3.—NPDES PERMIT REQUIREMENTS [1]—Continued

[Regional Permit Requirements]

Wastestream	Region X (Cl 1986 BPT permit)	Region X exploration permit (1993)	Region VI final drilling permit (1993)	Region VI production permit (final) (1995)	Region IV permit (1994)
	>20-40m = 750 bbl/hr. >5-20m = 500 bbl/hr. <5m = No discharge.				
"Dewatering Effluent".	Not separately regulated	Not separately regulated	No free oil 50 mg/l TSS. 125 mg/l COD pH = 6-9. 500 mg/l chlorides. 0.5 mg/l total Cr. 5.0 mg/l Zn Monitor volume.	Not applicable.	Not separately regulated.
Treatment, Completion, Workover Fluids.	No free oil (Static Sheen) No oil-based fluids pH = 6-9 Oil and grease limits apply to combined discharge of any TWC commingled with produced water	No discharge of free oil or oil-based fluids. Monitor frequency of discharge and volume pH = 6.5–8.5. Oil & grease = 72 daily max. & 48 mo. avg	Freshwater: No discharge. Saline water: No toxics, No free oil (visual sheen), pH = 6-9	Not applicable.	No Discharge.
Domestic Wastes	No free oil (No visible sheen). No Floating solids Monitor flow rate	Monitor flow rate No free oil (No visible sheen). No floating solids No visible foam	No discharge of solids ("garbage").	Not applicable.	Flow = 10,000 gpd max. BOD_5 = 45 mg/l daily max. = 30 mg/l (mo. aver.) TSS = 45 mg/l daily max. = 30 mg/l (mo. aver.) Total residual chlorine = 1.0 mg/l (daily min) maintained as close to this value as possible. No Floating Solids.
Deck Drainage	No free oil (Visual Sheen) Monitor flow rate (mo. ave.).	Monitor flow rate (mo. avg.) No free oil (visual sheen).	No free oil (visual sheen) Monitor volume.	Not applicable.	Monitor daily flow No free oil (visual sheen)
Sanitary Wastes	No floating solids As close as possible to, but no less than 1.0 mg/l. BOD & SS [2] 24 hr = 60 mg/l 7 day = 45 mg/l	No free oil (No visible sheen). No floating solids No visible foam As close as possible but no less than 1 mg/l. BOD: 30 day=30 mg/l.	No floating solids BOD = 45 mg/l TSS = 45 mg/l fecal coliforms = 200/100 mls Monitor flow.	Not applicable.	Flow = 10,000 gpd max. BOD_5 = 45 mg/l daily max. = 30 mg/l (mo. aver.) TSS = 45 mg/l daily max. = 30 mg/l (mo. aver.) Total residual chlorine = 1.0 mg/l (daily min) maintained as close to this value as possible. No Floating Solids.

TABLE 3.—NPDES PERMIT REQUIREMENTS [1]—Continued

[Regional Permit Requirements]

Wastestream	Region X (CI 1986 BPT permit)	Region X exploration permit (1993)	Region VI final drilling permit (1993)	Region VI production permit (final) (1995)	Region IV permit (1994)
	30 day = 30 mg/l	24 hr = 60 mg/l TSS: 30 day = TSS intake + 30 mg/l. 24 hr = TSS intake + 60 mg/l			

[1] For a complete presentation of the effluent limitations and their bases in the permits see the following: Region X Proposed General Permit for Cook Inlet: 50 FR 28974, 7/17/85, Region X Final Permit for Cook Inlet: 51 FR 35460, 10/3/86, Region VI Final General Permit for Drilling Operations: 58 FR 49126, 9/21/93, Region VI Proposed General Permit for Production Operations: 57 FR 60926, 12/22/92. The Region X Exploration Permit and the Region IV Permit are in the record for this rulemaking.

[2] Limits apply only to discharges to state waters and separately for BOD and SS.

V. Summary of Data Gathering Efforts

The major studies presenting information on coastal oil and gas effluents and treatment technologies which have bearing on this proposed rule are summarized in this section. These investigations include: underground injection of produced water and associated produced water treatment technologies; solids control technologies for drilling fluids; drilling fluids and drill cuttings waste generation, treatment, and disposal in coastal Alaska; and commercial non-hazardous oil and gas waste disposal facilities and technologies. In addition, EPA sent a CWA section 308 Questionnaire to the industry to gather information characterizing coastal oil and gas pollution control technology and the costs of such technologies. The questionnaire and results are described below.

A. Information Used From the Offshore Guidelines

Due to certain similarities in the technologies employed and wastes generated by the offshore and coastal subcategories of the oil and gas industry, certain data generated during the Offshore Guidelines development effort have been utilized in the development of this proposed rule where appropriate. Those data most influential in the development of this proposed rule, listed below, are summarized both in the Coastal Technical Development Document and described in more detail in the Development Document for the Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, (hereafter referred to as the Offshore Technical Development Document), Sections V and XVIII (EPA, January 1993).

- Produced water characteristics for Cook Inlet.
- Produced water characteristics for effluent from improved gas flotation.
- Drilling fluids and cuttings waste characteristics.
- Deck drainage characteristics.
- Domestic waste characteristics.
- Sanitary waste characteristics.
- Some non-water quality environmental impacts.

B. 1993 Coastal Oil and Gas Questionnaire

A comprehensive questionnaire entitled the ''1993 Coastal Oil and Gas 308 Questionnaire'' was developed under the authority of section 308 of the CWA. EPA distributed this questionnaire to all known coastal oil and gas operators. The Questionnaire requested information on oil and gas waste generated, their treatment and disposal methods and costs for waste treatment and disposal. The questionnaire also requested information regarding the financial profile of each operator surveyed.

Upon their return, EPA reviewed the questionnaires for completeness and technical content and then transcribed the responses into a computer readable format using double key-entry procedures. EPA prepared statistical estimates in order to extrapolate the results from the sampled wells and facilities to the entire coastal industry. EPA used the individual data and the statistical reports to determine waste volumes, treatment and disposal methods and costs of treatment and disposal methods. EPA also used the survey results to estimate future industrial activity. The statistical analysis of the questionnaire data is included in the record for this rulemaking.

C. Investigation of Solids Control Technologies for Drilling Fluids

In 1993, EPA collected samples and gathered technical data at three drilling operations in the coastal region of Louisiana. The purpose of this effort was to gather operating and cost information regarding closed-loop solids control technology (See description of this technology in Section VI.A) at active oil and gas well drilling operations. Two of the sites were drilling using land-based rigs, and the other operation was located in an inland bay and used a posted barge rig. One operator was a large independent, the other 2 were majors.[1]

Technical and cost information was collected on the following topics:

- Drilling waste volumes and disposal methods.
- Solids control equipment design and performance.
- Drilling fluids.
- Well design and construction.
- Drilling operations.
- Annular injection.
- Miscellaneous waste volumes and disposal methods.

EPA used the results of this investigation to determine methods and costs of drilling waste disposal, as well as miscellaneous waste volumes, and their treatment and disposal.

D. Sampling Visits to 10 Gulf of Mexico Coastal Production Facilities

EPA visited ten coastal oil and gas production facilities located in Texas

[1] The term ''major'' oil and gas company is used here to differentiate it from smaller operators in the industry. Major oil and gas companies are characterized by a high degree of vertical integration, *i.e.*, their activities encompass both ''upstream'' activities—oil exploration, development, and production and ''downstream'' activities—transportation, refining, and marketing. As a group the majors generally produce more oil and gas, earn significantly more revenue and income, have considerably larger assets, and have greater financial resources than the independent operators.

and Louisiana to gather operating and cost information regarding produced water injection and to collect samples of produced water and miscellaneous wastes. Samples were analyzed for a variety of analytes in the categories of organic chemicals, metals, conventional and non-conventional pollutants, and radionuclides. Sampling at each site was conducted for one day over a span of eight hours. Technical and cost data were collected in addition to the production waste samples.

EPA was careful, in its selection of Gulf Coast sites, to visit facilities that (1) were located in both Texas and Louisiana, (2) were located in different wetland situations (wetlands, or inland bays), and (3) that ranged in operator size (major to small independent). Nine of the ten facilities visited utilized injection wells for produced water disposal and one utilized surface discharge.

A focus of this site visit program was to investigate the technologies used to treat produced waters prior to injection. Several of the facilities employed cartridge filtration subsequent to BPT treatment (gravity separation sometimes assisted by heat or chemicals).

Aqueous samples were collected from settling tank effluent at all ten facilities, as well as the influent (settling effluent) and effluent of all four filtration systems. Samples were analyzed for the following analytes:

—TSS
—Oil and Grease
—Volatile Organics
—Semi-volatile Organics
—Metals
—Conventional Parameters
—Non-conventional Parameters
—Radionuclides

Cartridge filters were also collected at all the facilities that utilized them, and were analyzed for radionuclides concentrations. Samples of produced sands were also collected where available and analyzed for the same pollutants as for produced water.

In addition to the sampling activities, technical and cost information was collected on the following topics:

- Separator and treatment system technologies and configuration.
- Equipment space requirements.
- Support structures.
- Miscellaneous waste volumes treatment and disposal methods.
- Produced water volumes and disposal methods.
- Energy requirements.
- Injection well remedial work requirements.
- Ancillary equipment requirements (besides the injection well) for injection.
- Injection well design and operation.
- Production data.

The results from this study, together with data from the EPA 1993 Coastal Oil and Gas Questionnaire and state permit data, discussed below, formed the basis for EPA's produced water treatment and disposal cost analyses discussed later in Section VI.B. The analytical data was used to characterize produced water effluent characteristics from BPT treatment systems.

E. State Discharge Monitoring Reports

EPA obtained detailed information on produced water discharges from state discharge permits for operators in Texas and Louisiana. The Louisiana Department of Environmental Quality (LADEQ) and the Texas Railroad Commission (TRC) supplied EPA with state permits for all known dischargers in the coastal areas. The state permit information identifies the operator, the name of the producing field, the location of the production facility, the volume of produced water discharged, the location and permit number of the outfall, and in Louisiana only, the compliance date by which the discharge must cease. From these data, EPA estimated that 216 production facilities in both the Texas and Louisiana coastal region will be discharging after July 1996 (the projected date of issuance of this regulation). The list of these facilities is presented in the record for the rulemaking. From this list EPA estimated costs of produced water treatment and disposal on a per facility basis.

F. Commercial Disposal Operations

In May 1992, EPA visited two non hazardous oil and gas waste land treatment facilities and two waste transfer stations in Louisiana. The purpose of these visits was to investigate the transportation, handling, disposal methods employed and associated costs of these operations. Detailed information was gathered concerning the operation of the landfarm treatment process used for the disposal of non-hazardous oil field wastes, transportation equipment, transfer equipment, equipment fuel requirements and costs incurred by the facilities and costs charged to the customers. The information was used in the development of compliance costs and the non-water quality environmental impacts for the various regulatory options under consideration.

In March 1992, EPA visited two commercial produced water injection facilities in Louisiana. The purpose of the visits was to collect information regarding costs of produced water disposal and other operating costs as well as to collect samples of produced water, filter solids, used filters and tank bottoms solids for radioactivity analysis. Both facilities utilized sedimentation and filtration as treatment processes for produced water followed by underground injection. The technical information gathered at these sites was used in developing compliance costs and the non-water quality impacts for the various regulatory options under consideration. The results of the radioactivity analyses were used in an evaluation of radioactivity concentrations in oil and gas wastes.

G. Evaluation of NORM in Produced Waters

EPA reviewed all known data regarding the presence of naturally occurring radioactive materials (NORM) found in discharge of produced water and associated with scales and sludges on oil and gas production equipment.

EPA summarized produced water radioactivity data from 22 available studies focusing on data from coastal sites. Each of these 22 studies was summarized according to the location of the sites, sampling plans, and analytical methods used to measure the radionuclides. This information was used in characterizing NORM in produced water discharges in the Gulf Coast.

H. Alaska Operation

In August 1993, EPA embarked on a fact-finding mission regarding drilling and production operations and practices in both regions of Alaska, Cook Inlet and the North Slope. Information and data were obtained by direct visits to these areas, and by contacting the Alaska Oil and Gas Association (AOGA), state regulatory authorities, and individual operators. In addition, AOGA and individual operators submitted to EPA information on projects and technologies currently being developed and used in Cook Inlet and on the North Slope to dispose of drilling and production wastes, and the costs associated with these projects. Specific operating and cost information was obtained on zero discharge technologies including grinding and injection systems for drilling fluids and drill cuttings as well as produced water injection. EPA used the information obtained during this data gathering effort to estimate costs of treatment and control options for Alaska coastal facilities.

In March 1994, Cook Inlet Alaska oil and gas operators submitted to EPA information on drilling waste disposal alternatives and their costs and on projected drilling schedules. Three alternatives were evaluated by the operators in terms of technological achievability and costs: discharge to Cook Inlet surface water, land-based disposal, and disposal by injection. EPA considered this information during its development of regulatory options and estimation of costs for disposal of drilling wastes in Cook Inlet. These same Cook Inlet operators also submitted to EPA information on the technological and economic feasibility of zero discharge of produced water from the largest shore-based production facility in the Inlet. This information presented the costs and technological achievability for three produced water injection alternatives including (1) Treatment and injection at the platforms, (2) treatment at onshore treatment facilities (for some platform operations) and onshore injection, and (3) treatment at onshore treatment facilities and injection back at the platforms. EPA considered this information during its development of zero discharge option for produced water and cost estimations in Cook Inlet.

I. Region X Drilling Fluid Toxicity Data Study

EPA evaluated a summary data base containing Region X permit compliance monitoring information including toxicity measurements of drilling fluids used in Alaska. The database contains 161 records of 96-hour LC50 data from coastal and offshore oil and gas wells in Alaska from 1985 to 1994. Drilling fluid toxicity levels were characterized for Alaska drilling activities, and particularly for activities in Cook Inlet. This data indicated that drilling fluids and cuttings being discharged in Cook Inlet may be able to meet a toxicity limitation of between 100,000 ppm (SPP) and 1,000,000 ppm (SPP).

EPA measures toxicity using a standard bioassay test known as the ''Drilling Fluids Toxicity Test'' (See 40 CFR 435 Subpart A, Appendix 2). Under this test, the species mysidopsis bahia is exposed to different concentrations of the drilling fluids and cuttings for a set time, 96 hours. An LC–50 toxicity test is performed by mixing a solution of seawater and drilling fluids and cuttings, allowing the solution to settle for one hour, decanting the liquid off from the settled solids, and then adding to the decant, or suspended particulate phase (SPP), the test organisms and determining the number of organisms alive after 96 hours. Then, by observing mortality rates and by calculation, the concentration required to kill 50 percent of the test animals in 96 hours is determined. The ''96-hour LC–50'' is defined as the lethal concentration of a toxicant that will kill 50 percent of the test organisms after a 96-hour exposure. Thus, the lower the LC–50 value, the higher the relative toxicity.

J. California Operations

EPA visited coastal oil and gas operations in Long Beach Harbor, California in February 1992. The visit was to one of the four man-made islands that have been constructed in the Harbor for the purpose of oil and gas extraction. The facilities on these islands are operated by THUMS, a consortium of five oil and gas operating companies (Texaco, Humble (now Exxon), Union, Mobil and Shell). EPA met with state regulatory officials and was given a tour of one of the islands by THUMS personnel. Both drilling and production were occurring at the time of the visit.

Information regarding waste generation, treatment, disposal, and costs were obtained during the visit. No discharges are occurring from the THUMS operations. The information provided EPA with specific waste disposal technology and cost information which has, where appropriate, been incorporated into cost analyses, and enabled EPA to characterize California coastal oil and gas operations.

K. OSW Sampling Program

EPA's Office of Solid Waste conducted a sampling program on associated oil and gas wastes in 1992. As part of this effort, samples were obtained for completion, workover, and treatment fluids. The parameters analyzed for were the same as those for produced water samples listed previously in Section V.D. EPA has used this data base to characterize the discharges of these fluids. Seven samples of treatment, workover and completion fluids were collected from operations in Texas, New Mexico and Oklahoma. The samples were analyzed for conventional, nonconventional and priority pollutants.

L. Estimation of the Inner Boundary of the Territorial Seas

As part of the Coastal Guidelines development effort, EPA specifically delineated the seaward boundary of the coastal subcategory (which is the inner boundary of the Territorial Seas). The purpose of this effort was to define an area in order to estimate the number of coastal wells and production facilities operating in that area. The purpose was not to determine a well's subcategory for regulatory permit writers. This delineation is in the form of latitude and longitude coordinates covering that part of the inner boundary of the Territorial Seas along Alaska's North Slope and Cook Inlet, Texas, Louisiana, Alabama and Southern California. Much of this boundary has been delineated on nautical charts published by the National Ocean Service of the National Oceanic and Atmospheric Administration (NOAA). In some locations however, this boundary has not previously been delineated by NOAA, and EPA completed the coordinates using established procedures described in the Convention of the Territorial Seas and the Contiguous Zone, Articles 3–13. The digital coordinates of the inner boundary of the Territorial Seas, for the above mentioned locations and a description of its derivation is included in the record for this rule. This digital boundary assisted EPA in its determination of the number of wells and production facilities that exist in this subcategory.

VI. Development of Effluent Limitations Guidelines and Standards

A. Drilling Fluids and Drill Cuttings (Drilling Wastes)

1. Waste Characterization

Drilling fluid and cuttings discharges are typically generated in bulk form and occur intermittently during well drilling and at the end of the drilling phase.

There are currently no drilling fluids and cuttings discharges in any coastal area except Cook Inlet. In Cook Inlet, operators do not currently practice zero discharge, except for a small volume of drilling fluids and cuttings wastes (approximately one percent) which are not discharged because they do not meet current permit limits. Generally, drilling fluids and cuttings volumes average approximately 14,000 barrels (bbl) per new well drilled in Cook Inlet. (NOTE: The barrel is a standard oil and gas measurement and is equal in volume to 42 gallons). Based on industry projections given to EPA, an average of 79,000 bbls drilling fluids and cuttings are generated each year (bpy) in the Inlet. Significant pollutants in these wastes include chromium, copper, lead, nickel, selenium, silver, beryllium and arsenic among the toxic metals. Toxic organics present include naphthalene, fluorene, and phenanthrene.

TSS makes up the bulk of the pollutant loadings, part of which is comprised of the toxic pollutants. TSS concentrations are very high due to the nature of the wastes. And because its TSS concentration is so high, discharges of drilling fluids and cuttings can cause reduced light penetration resulting in decreased sea life primary productivity, fish kills or reduced growth rate, interference in development of fish eggs and larvae, modifications of fish movement and migration, and reduction of the abundance of food available to fish. Benthic smothering from settleable materials results in potential damage to invertebrate populations and potential alterations in spawning grounds and feeding habitats.

Operators use solids control equipment to remove drill cuttings from the drilling fluid systems which allows drilling fluids to be recycled and reduces the total amount of drilling wastes generated. Depending on the drilling solids control system and the method of waste storage and disposal onsite, a small wastestream, termed ''dewatering effluent'' may be segregated from the drilling fluids and cuttings. Dewatering effluent may be discharged from reserve pits or tanks which store drilling wastes for reuse or disposal. Dewatering effluent may also be generated in enhanced solids control systems. Enhanced solids control systems, also known as closed-loop solids control operations, remove solids from the drilling fluid at greater efficiencies than conventional solids removal systems. Increased solids removal efficiency minimizes the buildup of drilled solids in the drilling fluid system, and allows a greater percentage of drilling fluid to be recycled. Smaller volumes of new or freshly made fluids are required as a result. An added benefit of the closed-loop technology is that the amount of waste drilling fluids can be significantly reduced. The installation of reserve pits is unnecessary in closed-loop systems for this reason. Dewatering effluent is generated in the process of drilling fluids solids removal and can either be reused (it often contains expensive reusable chemicals), or disposed of.

EPA's general permit for drilling operations for TX and LA included limitations for the discharge of dewatering effluent (See Section VI.E). However, the 1993 Coastal Oil and Gas Questionnaire results show that few operators discharge dewatering effluent as a separate wastestream. Additionally, contacts with industry indicate that the volume of dewatering effluent from reserve pits is small if nonexistent as the use of pits is phasing out due to state permit conditions, environmental or land owner concern, or the expanding use of closed-loop systems. EPA site visits to drilling operations, where these closed-loop systems were in place, showed that none of the dewatering effluent was discharged. Instead, it is either recycled, or sent with other drilling wastes to commercial disposal. Operators at these facilities explained that it is less expensive to send this wastestream along with drilling fluids and drill cuttings for onshore disposal rather than to treat for discharge.

2. Selection of Pollutant Parameters

a. Pollutants Regulated

In the coastal subcategory, EPA is proposing to establish BAT, NSPS, and pretreatment standards that would require zero discharge of drilling fluids and drill cuttings. Where zero discharge is required, EPA would be controlling all pollutants in the wastestream.

EPA is also considering an alternative BAT limit applicable only to Cook Inlet, that in addition to the BPT requirement prohibiting the discharge of free oil, would also prohibit the discharge of diesel oil and limit toxicity and specify the cadmium and mercury content in stock barite. As presented in Section VI of the Offshore Technical Development Document, the prohibitions on the discharge of free oil and diesel oil would effectively remove toxic, nonconventional, and conventional pollutants. Diesel oil and free oil are considered, under BAT and NSPS, to be ''indicators'' for the control of specific toxic pollutants present in the complex hydrocarbon mixtures used in drilling fluid systems. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. Additionally, diesel oil may contain from 20 to 60 percent by volume polynuclear aromatic hydrocarbons (PAH's) which constitute the more toxic components of petroleum products.

Control of diesel oil would also result in the control of nonconventional pollutants under BAT and NSPS. Diesel oil contains a number of nonconventional pollutants, including PAHs such as methylnaphthalene, methylphenanthrene, and other alkylated forms of the listed organic priority pollutants.

EPA is proposing to establish BCT limitations for drill fluids and drill cuttings that would prohibit discharge of free oil (using the static sheen test) for Cook Inlet, and would require zero discharge everywhere else. The prohibition on the discharge of free oil (in addition to the zero discharge requirement) would effectively reduce or eliminate the oil and grease in these discharges. EPA is limiting free oil under BCT as a surrogate for oil and grease in recognition of the complex nature of the oils present in drilling fluids, including crude oil from the formation being drilled.

Prohibiting the discharge of diesel oil and free oil eliminates discharges of the above-listed constituents, to the extent that these constituents are present in either of these two parameters, and reduces the level of oil and grease present in the discharged drilling fluids and cuttings. Also under this alternative option, limitations on cadmium and mercury content in barite would control toxic and nonconventional pollutants in drilling fluids and cuttings discharges. This limitation would indirectly control the levels of toxic pollutant metals because cleaner barite that meets the mercury and cadmium limits is also likely to have reduced concentrations of other metals. Evaluation of the relationship between cadmium and mercury and the trace metals in barite shows a correlation between the concentration of mercury with the concentration of arsenic, chromium, copper, lead, molybdenum, sodium, tin, titanium and zinc (See the Offshore Technical Development Document in Section VI).

Toxicity of drilling fluids and cuttings is being regulated as a nonconventional pollutant that controls certain toxic and nonconventional pollutants. It has been shown, during EPA's development of the Offshore Guidelines, that control of toxicity encourages the use of less toxic, water-based drilling fluids, and where absolutely necessary, the use of less mineral oil added to a drilling fluid (and the pollutants, such as the PAH's, identified as constituents of mineral oil). A toxicity limitation would thus encourage the use of the lowest toxicity drilling fluids and the use of low-toxicity drilling fluid additives.

b. Pollutants Not Regulated.

Where zero discharge would be required, all pollutants would be controlled in drilling fluids and cuttings discharges. Where discharges with limitations would be required, (specifically if EPA selected the alternative BAT option in Cook Inlet), EPA has determined that it is not technically feasible to specifically control each of the toxic constituents of drilling fluids and cuttings that are controlled by the limits on the pollutants proposed for regulation.

EPA has determined that certain of the toxic and nonconventional pollutants are not controlled by the limitations on diesel oil, free oil, toxicity, and mercury and cadmium in stock barite. EPA exercised its discretion not to regulate these pollutants because EPA did not detect these pollutants in more than a very few of the samples from EPA's field sampling program and does not believe them to be found throughout the industry; the pollutants when found are present in trace amounts not likely to cause toxic effects; and due to the large number and variation in additives or specialty chemicals that are only used intermittently and at a wide variety of drilling locations, it is not feasible to set limitations on specific compounds contained in additives or specialty chemicals.

3. Control and Treatment Technologies

a. Current Practice.

BPT effluent limitations guidelines for coastal drilling fluids and drill cuttings prohibit the discharge of free oil (using the visual sheen test). However, because of either EPA general permits, state requirements, or operational preference, no drilling fluids and cuttings discharges are occurring in the North Slope, the Gulf coast states, or California. The only coastal operators discharging drilling fluids and cuttings are located in Cook Inlet. In Cook Inlet, neither diesel nor mineral-oil-based drilling fluids or resultant cuttings may be discharged to surface waters because they have been shown to cause a visible sheen upon the receiving waters. Compliance with the BPT limitations may be achieved either by product substitution (substituting a water-based fluid for an oil-based fluid), recycle and/or reuse of the drilling fluid, or by onshore disposal of the drilling fluids and cuttings at an approved facility.

NPDES permits issued by EPA for Cook Inlet drilling operations have also included BAT limitations based on ''best professional judgement'' (BPJ). The permit requirements allow discharges of drilling fluids and drill cuttings provided certain limitations are met including a prohibition on the discharges of free oil and diesel oil, as well as limitations on mercury, cadmium, toxicity and oil content. (See Section IV.E for a summary of the permits). Operators may employ any number of the following waste management practices to meet those permit limitations:

* Product substitution—to meet prohibitions on free oil and diesel oil discharges, as well as the toxicity and/or clean barite limitations,
* Onshore treatment and/or disposal of drilling fluids and drill cuttings that do not meet the toxicity or clean barite limitations,
* Waste minimization—enhanced solids control to reduce the overall volume of drilling fluids and drill cuttings, and
* Conservation and recycling/reuse of drilling fluids.

Refer to the Coastal Technical Development Document, Sections VII-VIII for a detailed discussion of each of these waste minimization techniques.

b. Additional Technologies Considered.

EPA has evaluated an additional method for drilling fluid and cuttings control and treatment in order to achieve zero discharge: namely, grinding and injection of drilling wastes. This process involves the grinding of the drilling fluids and drill cuttings into a slurry that can be injected into a dedicated disposal well. The grinding system consists of a vibrating ball mill which pulverizes the cuttings and creates an injectable slurry. Recent information has shown that this comparatively contemporary technology has been successfully demonstrated on the North Slope for drilling waste disposal, and is being introduced both in the Gulf Coast coastal areas as well as in Cook Inlet. EPA, therefore believes that this technology is available to coastal operators.

In addition to grinding and injection, EPA has also investigated the feasibility of onshore disposal of this wastestream. For the coastal subcategory drilling activities, in areas other than Cook Inlet, current permits or practice (in the case of the North Slope) require zero discharge of drilling fluids and cuttings. On-land disposal sites located in Alaska are available in these areas and are being utilized to comply with the zero discharge requirement. On-land disposal sites are also available to two out of the five Cook Inlet operators. These two operators jointly operate an oil and gas landfill disposal site on the west side of the Inlet. Using projected drilling schedules provided by industry, EPA estimated that these two operators would generate approximately 76 percent of the drilling wastes produced by the Cook Inlet operators over the next seven years following the scheduled 1996 promulgation of this rule. EPA has determined that there is sufficient on-land disposal capacity to accept all of the drilling fluids and cuttings generated by these two operators at this disposal facility.

EPA investigated the logistical difficulties of storing and transporting drilling wastes in the Cook Inlet, due to the extensive tidal fluctuations, strong currents, and ice formation during winter months. While these climatological and tidal situations may cause complications, EPA has determined that they do not pose insurmountable technical barriers. EPA has taken into consideration supplementary costs incurred by additional winter transportation and storage of drilling wastes in its cost evaluation of the zero discharge requirement as described later in Section VI.A.

No on-land oil and gas waste disposal facilities are available in Alaska to the other three Cook Inlet operators who plan to drill after promulgation of this rule. EPA investigated the possibility of disposing of drilling wastes at an on-land oil and gas waste disposal site available to Cook Inlet operators located in Idaho. EPA determined that, while it is generally more economical to dispose of drill wastes via grinding and injection, in the case of smaller volumes of drilling wastes, it would be more cost effective to dispose of the wastes by shipping them to the Idaho disposal facility.

Land disposal of oil and gas wastes is also available to Cook Inlet operators at a disposal facility located in Oregon. EPA performed its costing of land disposal assuming the use of the Idaho facility (see discussion of costs later in this section). EPA expects that costs to dispose of the wastes at the Oregon facility would be close to or less than costs using the Idaho facility because transportation of wastes to the Oregon facility would utilize barging to a greater extent, making overall transportation costs less.

The results of this investigation show that the volume of drilling fluids and drill cuttings wastes generated in Cook Inlet can be either disposed of on-land or by grinding and injection. However, during the previous Offshore Guidelines rulemaking affecting Alaska offshore drilling operations, and early in the data gathering stages of this proposed rule, operators raised concerns that compliance with zero discharge could significantly interfere with drilling operations. EPA does not have sufficient information supporting these concerns, and solicits comments on these issues.

Therefore, for this proposal, EPA is also considering options which would allow the discharge of the drilling fluids and drill cuttings in Cook Inlet providing they were to meet certain limitations. These limitations would prohibit the discharge of diesel oil and free oil using the static sheen test, limit cadmium and mercury in the stock barite used in fluid compositions and toxicity at either 30,000 ppm (SPP) or a more stringent toxicity in range of 100,000 ppm (SPP) to 1 million ppm (SPP). Drilling fluids and drill cuttings not meeting these limitations would not be allowed to be discharged, and therefore, would have to be injected or sent to shore for disposal. EPA would base the more stringent toxicity limitations (based on further evaluation as discussed below), in part, on the volume of drilling wastes it determines could be injected or disposed of onshore without interfering with ongoing drilling operations.

Prior to, and during the offshore rulemaking, EPA conducted bioassay tests on eight generic mud types (encompassing virtually all water-based muds, exclusive of specialty additives, primarily used on the outer continental shelf), and, EPA established a toxicity limitation of 30,000 ppm (SPP). Even in offshore Alaska, drilling was not evaluated for specific locations, thus technical drilling requirements for adequate drilling with a focus on small localized areas were not considered in setting the limitation for the offshore rule. One alternative option for the coastal rule would be to set the limitations for Cook Inlet equal to the offshore limitations for Alaska.

As discussed above, another option would retain the offshore limitations but require a more stringent toxicity requirement. The toxicity limit would be based on a relationship between the achievable toxicity of the drilling wastes and the volume of these wastes that could be disposed of onshore or by grinding and injection without interfering with ongoing drilling operations (e.g., some fraction of the volume of wastes generated and covered by the zero discharge option).

In order to determine the appropriate toxicity level for the more stringent toxicity option, EPA attempted to evaluate effluent toxicity test results for Cook Inlet drilling fluids and cuttings discharges. EPA reviewed permit compliance monitoring records, from EPA's Region 10, containing 161 sets of results for toxicity testing of drilling fluids and drill cuttings used in the Alaska offshore and coastal regions between 1985 and 1994. (The measure of toxicity is a 96 hour test that estimates the concentration of drilling fluids suspended particulate phase (SPP) that is lethal to 50 percent of the test organisms.) The records were summarized into a database which was evaluated on the basis of the toxicity of drilling fluids and drill cuttings used in Alaska as a whole and Cook Inlet in particular. After sorting the database to eliminate inadequate data, such as drilling fluids contaminated by pills and incomplete toxicity tests, 104 sets of results were retained for all of Alaska, with 59 of these from Cook Inlet.

Of the Cook Inlet bioassay test results, 83 percent were less toxic than 100,000 ppm (SPP); 60 percent were less toxic than 500,000 ppm; and one percent exhibited no toxic effect (i.e., 1 million ppm or greater with less than 50 percent mortality of the test organism). (Note that toxicity is inversely related to the 96-hour bioassay results so as the values cited above increase, toxicity decreases).

These evaluations utilized an available database obtained from EPA's Region 10, which provides an account of the relationship between toxicity and drilling fluids currently being discharged. The toxicity values are identified in the available database by operator, permit number, well name, date and base fluids system (mud). In addition, some of the values are related to an identified volume of muds discharged. However, many of the values in the summary do not have either a volume identified or whether the drilling fluids were discharged. This available database is presently being updated as EPA continues to identify the volume of drilling wastes having been discharged in Cook Inlet related to specific toxicity test results. EPA solicits any information useful in determining an appropriate toxicity limitation that individual Cook Inlet operators have including data on the specific amounts of drilling wastes generated versus discharged and their corresponding toxicity test results.

4. Options Considered

EPA has developed three options for the control and treatment of drilling fluids and drill cuttings. As mentioned earlier in this preamble, dewatering effluent may be a wastestream generated separately. However, because it consists of constituents that originate entirely within the drilling fluids and cuttings solids control system, EPA will not be regulating dewatering effluent separately. Rather, EPA proposes to make the drilling fluids and cuttings options applicable to the dewatering effluent wherever this wastestream may be generated.

The three options considered by EPA contain zero discharge for all areas, except two of the options contain allowable discharges for Cook Inlet. One of these options which would allow discharges meeting a more stringent toxicity limitation would require an additional notice for public comment since the specific toxicity limitation has not been determined at this time (as discussed in this section). The three options are:

Option 1: Zero discharge for all areas except Cook Inlet where discharge limitations require toxicity of no less than 30,000 ppm (SPP), no discharge of free oil and diesel oil and no more than 1 mg/1 mercury and 3 mg/1 cadmium in the stock barite.

Option 2: Zero discharge for all areas except for Cook Inlet where discharge limitations would be the same as Option 1, except toxicity would be set to meet a limitation between 100,000 ppm (SPP) and 1 million ppm (SPP).

Option 3: Zero Discharge for all areas.

As discussed later in this section, all of the above options are being co-proposed.

Option 1 would require zero discharge of drilling fluids and cuttings for all coastal drilling operations except those located in Cook Inlet. Allowable discharge limitations for drilling fluids and cuttings in Cook Inlet would require compliance with a toxicity value of no less than 30,000 ppm (SPP); no discharge of free oil (as determined by the static sheen test); no discharge of diesel oil and 1 mg/kg of mercury and 3 mg/kg of cadmium in the stock barite. (These are the same limitations as those for offshore drilling operations waste discharges in the Alaska.)

Option 2 would require all operators to meet the same zero discharge limitation for the drilling fluids and cuttings in all areas except for Cook Inlet. In Cook Inlet, the drilling fluids and cuttings discharges would be required to meet the same limitations as in Option 1 except that a more stringent toxicity limitation would be imposed. Instead of meeting a toxicity limitation of 30,000 ppm (SPP), a toxicity limitation between 100,000 ppm (SPP) and 1 million ppm (SPP) would be met.

The toxicity limitation range of between 100,000 ppm (SPP) and one million ppm (SPP) reflects the range of toxicity measurements resulting from EPA's evaluation of the current practice for drilling in Cook Inlet. As discussed previously in this section, an attempt was made in this evaluation to determine the volumes of drilling wastes being discharged and their respective toxicity levels. Because of the lack of identified discharge volumes for some of the toxicity test results, this determination could not be completed. Using the 83 percent of drilling wastes which reflects the fraction of test results less toxic than 100,000 ppm (SPP), and coincidentally also reflects the fraction of identified volumes less toxic than one million ppm (SPP), costs and discharge loadings were developed for this option. (The method used to derive this range is separate and distinct from the statistical methodologies generally used by EPA in effluent guidelines regulations to derive 30-day average and daily maximum limitations calculated from the 95th and 99th percentiles, respectively.) However, due to the above discussed limitations with the data base, EPA is currently only able to estimate an achievable toxicity limit in the range of 100,000 ppm (SPP) to one million ppm (SPP). As described earlier under

''Additional Technologies Considered'' of this section, EPA is continuing to evaluate toxicity test results and volumes and any other data for drilling fluids used and discharged in Cook Inlet in an effort to derive a more specific limitation and resulting revisions of costs and loadings. A supplemental notice presenting the data and revised results and soliciting comment would be necessary prior to promulgation.

Option 3 would prohibit the discharge of drilling fluids and cuttings from all coastal oil and gas drilling operations. This option utilizes grinding and injection and onshore disposal as a basis for complying with zero discharge of drilling fluids and cuttings.

The technology Options 1 and 2 for Cook Inlet have been developed taking into consideration the possibility that Cook Inlet operations are unique to the industry due to a combination of climate, transportation logistics, and structural and space limitations that interfere with the drilling operations. These options are based on a degree of recycling and reuse, onshore disposal and/or grinding and injection of a portion of the wastes if they cannot meet the limitations, in addition to product substitution in order to attain the limitations and be able to discharge a portion of the generated wastes.

EPA solicits comments on the two discharge options containing specific data on the toxicity levels achievable for drilling fluids compositions and drill cuttings and why the more toxic of the compositions must be used in order to successfully drill. Also, information is solicited on the degree to which zero discharge all would interfere with drilling operations in Cook Inlet, given the estimate of a limited amount of drilling planned.

5. BCT Options Selection

a. BCT Cost Test Methodology.

The methodology for determining ''cost reasonableness'' was proposed by EPA on October 29, 1982 (47 FR 49176) and became effective on August 22, 1986 (51 FR 24974). These rules set forth a procedure which includes two tests to determine the reasonableness of costs incurred to comply with candidate BCT technology options. If all candidate options fail either of the tests, or if no candidate technologies more stringent than BPT are identified, then BCT effluent limitations guidelines must be set at a level equal to BPT effluent limitations. The cost reasonableness methodology compares the cost of conventional pollutant removal under the BCT options considered with the cost of conventional pollutant removal at publicly owned treatment works (POTWs).

BCT limitations for conventional pollutants that are more stringent than BPT limitations are appropriate in instances where the cost of such limitations meet the following criteria:

• The POTW Test: The POTW test compares the cost per pound of conventional pollutants removed by industrial dischargers in upgrading from BPT to BCT candidate technologies with the cost per pound of removing conventional pollutants in upgrading POTWs from secondary treatment to advanced secondary treatment. The upgrade cost to industry must be less than the POTW benchmark of $0.53 per pound ($0.25 per pound in 1976 dollars indexed to 1992 dollars).

• The Industry Cost-Effectiveness Test: This test computes the ratio of two incremental costs. The ratio is also referred to as the industry cost test. The numerator is the cost per pound of conventional pollutants removed in upgrading from BPT to the BCT candidate technology; the denominator is the cost per pound of conventional pollutants removed by BPT relative to no treatment (i.e., this value compares raw wasteload to pollutant load after application of BPT). The industry cost test is a measure of the candidate technology's cost-effectiveness. This ratio is compared to an industry cost benchmark, which is based on POTW cost and pollutant removal data. The benchmark is a ratio of two incremental costs: the cost per pound to upgrade a POTW from secondary treatment to advanced secondary treatment divided by the cost per pound to initially achieve secondary treatment from raw wasteload. The result of the industry cost test is compared to the industry Tier I benchmark of 1.29. If the industry cost test result for a considered BCT technology is less than the benchmark, the candidate technology passes the industry cost-effectiveness test. In calculating the industry cost test, any BCT cost per pound less than $0.01 is considered to be the equivalent of de minimis or zero costs. In such an instance, the numerator of the industry cost test and therefore the entire ratio are taken to be zero and the result passes the industry cost test.

These two criteria represent the two-part BCT cost reasonableness test. Each of the regulatory options was analyzed according to this cost test to determine if BCT limitations are appropriate.

b. BCT Cost Calculations and Options Selection.

(i) Other than Cook Inlet.

In addition to considering setting the BCT limitations equal to BPT, EPA considered two additional BCT options for control of conventional pollutants in drilling fluids and drill cuttings. Both of these options would require zero discharge of drilling fluids and drill cuttings throughout the subcategory except in Cook Inlet. Because all operators throughout the entire subcategory, except in Cook Inlet, are currently meeting a zero discharge requirement, or in the case of dewatering effluent, are practicing zero discharge already, there is zero cost and zero removal of conventional pollutants for this limitation. Thus, EPA has determined that zero discharge passes the BCT cost tests and other statutory factors and proposes a BCT limitation equal to zero discharge for all areas except Cook Inlet.

(ii) Cook Inlet.

In Cook Inlet, EPA considered either zero discharge (Option 3, above), or allowing discharge based on requirements identified in Option 2, above. EPA did not consider Option 1 for Cook Inlet, allowing discharge at the current Offshore Guidelines limitations with a toxicity limit of 30,000 ppm (SPP), as a distinct BCT option because the amount of removal of the conventional pollutant oil and grease, as oil, from discharge by this level of toxicity could not be determined from that removed by the current BPT requirement of no free oil.

The POTW test (first part of the two part cost-reasonableness test) is calculated by comparing the cost per pound of conventional pollutant removed in upgrading from BPT to the BCT candidate options. EPA determined the costs of each BCT option for drilling fluids, drill cuttings, and drilling fluids and drill cuttings combined.

EPA included only oil and grease and TSS in the BCT analysis. EPA did not include BOD because it is not a parameter normally measured in wastewaters from this industry since it is associated with the oil content, e.g., oil and grease measurement. The use of BOD and oil and grease would result in double-counting, thus giving erroneous results. EPA did not include the parameter of settleable solids in the BCT analysis because settleable solids are not a conventional pollutant.

EPA calculated cost of the BPT limitations for drilling fluids and drill cuttings for Cook Inlet using the model well characteristics and disposal costs used for the offshore wells (in the development of the Offshore Guidelines). The volume of wastes (drilling fluids and cuttings) was based on the 1993 Coastal Oil and Gas Questionnaire data for Cook Inlet. EPA based the costs associated with meeting the BPT requirement of ''no free oil'' on land-based disposal of oil-based drilling fluids and oil laden cuttings and substitution of mineral oil for diesel oil in pills. As was done in the Offshore Guidelines BCT determinations, oil content, which is normally measured in drilling wastes, was used as surrogate for the oil and grease conventional pollutant in the calculation of pollutant removals. The following are annual BPT costs and conventional pollutant removals per well for drilling fluids and cuttings:

Annual Cost (1992 Dollars):
Drilling Fluids—$40,275
Drill Cuttings—$22,355
TSS Removals (Annual):
Drilling Fluids—267,911 pounds
Drill Cuttings—297,880 pounds
Oil and Grease Removals (Annual):
Drilling Fluids—207,584 pounds
Drill Cuttings—92,895 pounds

The three options for Cook Inlet were evaluated according to the BCT cost reasonableness tests. The pollutant parameters used in this analysis were total suspended solids and oil and grease. All options, except the ''BPT'' option, no discharge of free oil, fail the BCT cost reasonableness test. Costs for the ''BPT'' option are equal to zero because it reflects current practice. The results of the POTW test (first part of the BCT cost test) for the zero discharge option (Option 3) is $0.151 per pound of conventional pollutant removed. A value of less than $0.534 per pound (1992$) is required to pass the POTW test. Thus, this option passes the POTW test. The results of the Industry Cost Ratio Test (ICR) is 2.097. As this value of 2.097 is greater than 1.29, zero discharge for drilling fluids and drill cuttings in Cook Inlet fails the second test. Thus, EPA proposes that BCT be equal to BPT for drilling fluids and drill cuttings discharges in Cook Inlet.

EPA conducted the same set of tests for Option 3 for the separate wastestreams of drilling fluids and cuttings. The results of the BCT cost tests for Option 2 and 3 are contained in Table 3 of the preamble, show that drilling fluids fail the second test, and cuttings pass. (Results for Option 1 are equal to zero and are not shown on Table 3).

The same set of tests are conducted for the Option 2, prohibitions on the discharge of free oil and diesel oil, limitations on cadmium and mercury in stock barite and toxicity limitation of between 100,000 and 1 million ppm (SPP) or greater. For the purpose of conducting these calculations, a volume fraction of 0.83 (83 percent) of the drilling fluids and cuttings was anticipated to comply with a toxicity limitation of between 100,000 ppm (SPP) and 1 million ppm (SPP). A summary of the results of these tests, also presented in Table 4, demonstrate drilling fluids and cuttings both fail the cost test. Thus, both candidate BCT options fail the ICR test, and BCT is set equal to Option 1 for this proposal which is equal to zero discharge everywhere except for Cook Inlet where BPT would apply.

The specific calculation of these BCT cost reasonableness tests for the drilling fluids and drill cutting options for Cook Inlet are discussed further in the Coastal Technical Development Document.

TABLE 4.—BCT Cost Test Results for Drilling Fluids and Drill Cuttings for Cook Inlet[1]

Regulatory option	Pollutant removal (lb/well)	Compliance cost[1] ($/well)	BCT cost ($/lb)	Pass POTW (<0.534)[2]	BPT cost ($/lb)	ICR ratio	Pass ICR (<1.29)
Drilling Fluids							
Option 2	191,693	129,026	0.673	No	0.085		
Option 3	1,127,603	418,888	0.371	Yes	0.085	4.365	No.
Drill Cuttings							
Option 2	389,756	30,226	0.078	Yes	0.057	1.368	No.
Option 3	2,292,681	98,258	0.043	Yes	0.057	0.754	Yes.
Drilling Fluids and Cuttings							
Option 2	581,449	159,252	0.274	Yes	0.072	3.806	No.
Option 3	3,420,284	517,146	0.151	Yes	0.072	2.097	No.

[1] Results of Option are equal to zero and are not shown in this table.
[2] Compliance Cost and Conventional Pollutants Removal are incremental to BPT.
[3] 1986 benchmark (0.46) adjusted to 1992 dollars $0.534.

6. BAT and NSPS Options

EPA is co-proposing all three options considered for the BAT and NSPS level of control for drilling fluids and drill cuttings. A discussion of the costs and impacts and description of the selection rationale is contained below.

a. Costs.

No costs would be incurred by the industry to comply with Option 1 because the requirements are reflective of current practice. Costs incurred by the coastal industry to comply with Option 2 would amount to approximately $1.4 million annually. These costs are attributed only to the Cook Inlet operators who would be required to meet the Offshore limitations and a more stringent toxicity limitation based on an estimate that 83 percent of the drilling fluids and drill cuttings would pass a toxicity limitation of between 100,000 ppm (SPP) and 1,000,000 ppm (SPP). Thus, 17 percent of the drilling wastes would need to be disposed of either onshore or by grinding and injection.

Costs to comply with Option 3 (zero discharge all) are attributed only to Cook Inlet operators not currently meeting a zero discharge requirement for drilling fluids and drill cuttings (all other coastal operators including the North Slope of Alaska are already practicing zero discharge). Costs to comply with this option are estimated to be approximately $3.9 million annually for Cook Inlet operators. EPA conducted an extensive analysis of possible waste disposal options available to Cook Inlet operators in order to estimate the costs to comply with a zero discharge requirement. The basis for this cost analysis is that approximately 76 percent of the drilling fluids and cuttings generated in Cook Inlet would be hauled to shore for disposal onshore, and the other 24 percent would be injected following grinding, into dedicated disposal wells regulated by the Underground Injection Control (UIC) program.

Of the five Cook Inlet operators, two operators generate about 76 percent of the drilling fluids and drill cuttings in Cook Inlet and, have access to a landfill in Alaska. One operator has no future plans to drill. The remaining two operators, who generate about 24 percent of the drilling wastes, would be expected to, for costing purposes, grind and inject to comply with the zero discharge requirement. Out of the five Cook Inlet operators, information obtained by EPA in 1993 indicated that one of them had no plans to drill in the Inlet. Recent (1995) information from an additional Cook Inlet operator relates that this operator also no longer has plans to drill in the Inlet. EPA conservatively estimated that this operator would have drilled six new wells (out of a total of 36 for all of the Cook Inlet operators) in the next seven years. Due to the fact that this is very recent information, the cost and economic analyses presented in this preamble have not deleted these six drillings. Thus, the analysis was performed assuming only one operator, instead of two, operators will not be drilling. However, retaining these six drillings in the analyses will not only provide a conservative estimate of the costs and economic impacts, but may serve to cover future changes in oil and gas activity should decisions be made to resume drilling.

Costs for land disposal include water vessel transportation, storage prior to transport to the disposal facility, truck transportation to the disposal facility, and landfill disposal costs. Costs for grinding and injection include purchase or rental of the grinding, slurrying and pumping equipment, and costs to drill dedicated injection wells at the drill site.

To determine the volume of drilling wastes requiring disposal, EPA obtained the projected drilling schedules for the Cook Inlet operators using information from the 1993 Coastal Oil and Gas Questionnaire and contacts with industry. EPA's projections estimate that 36 new wells and 19 recompletions will be drilled in the seven years following scheduled promulgation of this rule. (Recompletions are drilling operations which utilize an existing well but drill to a deeper formation than that which the well was previously producing from). Using information about the volume of drilling fluids and drill cuttings generated per well, and the projected amount of drilling over the seven years following scheduled promulgation, EPA estimates that the total amount of drilling fluids and cuttings annually discharged from these drilling operations will be approximately 79,000 barrels.

EPA also considered the logistical difficulties of transporting drilling wastes in the Cook Inlet as part of in EPA's costing analysis of the options. To achieve zero discharge, certain platforms would transport drill wastes to the eastern side of Cook Inlet by supply boat during ice conditions, and store the wastes at a transfer station until they could be transported by barge to an existing landfill facility on the west side of the Inlet. During the summer months, transport of wastes would be accomplished by barge directly to the west side.

Costs for the two operators to dispose of their wastes in the Alaskan landfill average $39/barrel. Costs for the other two operators (one operator has no future plans to drill) to dispose of their wastes by grinding and injection average $53/bbl. A weighted average for disposal of 76 percent of the drilling wastes by Alaskan landfills and 24 percent by grinding and injection equates to $42/bbl. On a per well basis, this amounts to approximately $425,000 and $600,000 for each recompletion and new well drilled, respectively.

The costs to comply with Option 2 are approximately $1.4 million annually. Capital expenditures are close to those incurred to meet Option 3 due to the fact that most operators will be required to install the same equipment regardless of the amount of wastes requiring disposal. The economic impact analysis associated with this option would result in a 1.3 percent reduction in the estimated lifetime production for the existing platforms in Cook Inlet as a result of three wells not being drilled. The net present value of this production loss (reduction in producers' net income) is $263,000 or less than 0.1 percent of baseline net present value. The average well life decreases by 0.2 years as a result of this option.

The results of the economic impact analysis associated with the costs for the zero discharge all option (Option 3) for drilling fluids and cuttings show a 2.7 percent reduction in the estimated lifetime production for the existing platforms in Cook Inlet (an additional 2.6 percent over Option 2). The associated net present value loss of production is approximately $6.1 million. This is reflective of the estimate that Cook Inlet platforms may close on average, 11 months earlier than their projected average lifetime of 11 years without this requirement. There are no well or platform shutdowns or barriers to new drilling activities as a result of these costs. However, three new wells would not be drilled. The results of the economic impact analysis are discussed in Section VII of the preamble. For new sources, EPA expects that the costs of complying with NSPS would be equal to or less than those for existing sources.

An analysis of non-water quality environmental impacts for BAT and NSPS was performed. The estimated impacts for the options are discussed in Section VIII of the preamble. The increased energy use and air emissions and availability of land disposal sites and capacity are identified.

b. Rationale for Option Selection.

EPA has not selected a preferred option for control of drilling fluids and drill cuttings under BAT and NSPS but, rather is co-proposing all three options. EPA has determined, based on available information, that all three options are technologically and economically achievable and have acceptable non-water quality impacts. However, due to possible operational interferences (for Option 3), the lack of sufficient data to set a toxicity limitation more stringent than 30,000 ppm (SPP) (for Option 2) and the high cost-effectiveness results for both Options 2 and 3, a preferred option has not been selected. EPA solicits comments on the appropriateness of each option.

A large majority of operators are already discharging at levels less toxic than the toxicity limitations of 30,000 ppm (SPP) contained in Option 1. Thus, this is a no cost option incurring no economic or non-water quality environmental impacts.

Option 2 requires zero discharge for all operators except in Cook Inlet where operators would be required to meet the Offshore subcategory limitations in addition to a toxicity limitation of between 100,000 ppm (SPP) and 1,000,000 ppm (SPP). This option would cost $1.4 million annually and results in less than a 0.1 percent reduction in estimated lifetime production for Cook Inlet platforms which would not significantly reduce the profit potential for these operators. Option 2 would result in the removal of approximately 3.9 million pounds of pollutants being discharged per year (or 1264 pounds in toxic equivalents), assuming a volume of 17 percent of the discharges would not meet a toxicity limit of between 100,000 ppm and one million ppm (SPP) and would therefore be disposed of by grinding and injection or on land. Out of the 3.9 million pounds removed annually less than 0.02

percent consists of toxic priority pollutants (or 642 pounds).

Due to limitations with the data base, EPA is currently only able to estimate an achievable toxicity limit in the range of 100,000 ppm (SPP) to one million ppm (SPP). As described earlier under ''Additional Technologies Considered'' of this section, EPA is continuing to evaluate toxicity test results and volumes and other data for drilling fluids used and discharged in Cook Inlet in an effort to derive a more specific limitation. A supplemental notice presenting the data and soliciting comment would be necessary prior to promulgation.

Option 3 would cost the industry $3.9 million annually and result in the reduction of 23 million pounds of pollutants being discharged per year (or 7375 in toxic pounds equivalents). Zero discharge of drilling fluids and drill cuttings is widely practiced in other coastal areas other than Cook Inlet, including the Gulf of Mexico, California, and the North Slope of Alaska. In Cook Inlet, zero discharge is not currently practiced but for a small amount of drilling fluids (approximately one percent) that do not meet permit limits. Zero discharge is technologically available because operators are able to comply with zero discharge by either disposing of their drilling fluids and drill cuttings onshore or by grinding and injecting the waste. The costs of this option would result in a 2.7 percent reduction in the estimated lifetime production for Cook Inlet platforms, which would not significantly reduce the profit potential for these operators. Thus, EPA believes these costs are economically achievable. However, concerns have been raised that zero discharge would interfere with drilling operations, in part because the weather conditions and tidal fluctuations in the Inlet pose logistical difficulties for drilling waste transportation especially during winter months. In addition, while Option 3 would result in the removal of 23 million pounds of pollutants per year, less than 0.02 percent of which are toxic pollutants, the $3.9 million annually incurred by industry to remove the 3760 pounds of priority toxic pollutants indicates that this option is not cost effective. (See EPA's cost effectiveness report entitled Cost Effectiveness Analysis of Effluent Limitations Guidelines and Standards for the Coastal Oil and Gas Industry in the rulemaking record for this proposal and additional discussion in Section VII of this preamble.) In Cook Inlet, operators are not currently practicing zero discharge. EPA estimates that to comply with a total zero discharge requirement, 24 percent of the drilling fluids and drill cuttings would be ground and injected into dedicated wells, and 76 percent would be disposed of onshore.

EPA is soliciting comments on whether the drilling fluids and cuttings volumes removed by these options are deminimus, and on the effect that weather and transportation logistics, cost effectiveness, and other factors (e.g., types of fluids used and their composition, toxicity values, etc.) may have on the applicability, achievability and practicality of both Options 2 and 3.

EPA does not expect any new source development wells drilled in Cook Inlet in the seven years following the scheduled promulgation of this rule. This is because all development wells are expected to be drilled from existing platforms in Cook Inlet. According to the definition of new sources, these wells would be existing sources. Additionally, any drillings that may occur in the recently discovered Sunfish formation in Upper Cook Inlet, are projected to be exploratory wells, which are also existing sources according to the new source definition. Thus, no costs will be attributed to NSPS in Cook Inlet because no new sources are projected for this area. However, in the case that a new source would be drilled in Cook Inlet, EPA has determined that zero discharge would not pose a significant barrier to entry for the drilling project. The same options are being considered for NSPS as for BAT, and again, no one preferred NSPS option is being selected in this proposal. Costs may be less than BAT because process modifications can be incorporated into the drilling rig design prior to its installation rather than retrofitting an existing operation. Whenever EPA determines that BAT is economically achievable, equivalent NSPS requirements would also be economically achievable, and cause no significant barrier to entry. EPA solicits comments on whether NSPS should be more stringent than BAT for Cook Inlet drilling fluids and cuttings.

EPA also finds the non-water quality environmental impacts of Option 2 and zero discharge (Option 3) to be acceptable. Again, non-water quality environmental impacts attributable to this rule would occur only in Cook Inlet. The air emissions and energy requirements associated with waste transportation were calculated for the two operators expected to utilize onshore landfill disposal to accommodate the wastes from their drilling operations. For the remaining two operators who will be drilling and do not have access to onshore disposal, EPA has calculated the air emissions and energy requirements resulting from grinding and injection to meet zero discharge. EPA has found that these non-water quality environmental impacts represent only a very small fraction of the total air emissions and energy requirements from normal operations, and that these non-water quality environmental impacts are acceptable. As stated above, EPA does not expect any new sources to be initiated in Cook Inlet. EPA, however, believes that the non-water quality environmental impacts resulting from any such activity would be equal to or less than those anticipated for existing sources, which EPA has found acceptable.

8. PSES and PSNS

Section 307 of the CWA authorizes EPA to develop pretreatment standards for existing sources (PSES) and new sources (PSNS). Pretreatment standards are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of publicly owned treatment works (POTWs). The pretreatment standards for existing sources are to be technology based and analogous to the best available technology economically achievable (BAT) for direct dischargers. The pretreatment standards for new sources are to be technology-based and analogous to the best available demonstrated control technology used to determine NSPS for direct dischargers. New indirect discharging facilities, like new direct discharging facilities, have the opportunity to incorporate the best available demonstrated technologies, including process changes, and in-plant controls, and end-of-pipe treatment technologies. EPA determines which pollutants to regulate in PSES and PSNS on the basis of whether or not they pass through, interfere with, or are incompatible with the operation of POTWs.

Based on the 1993 Coastal Oil and Gas Questionnaire and other information reviewed as part of this rulemaking, EPA has not identified any existing coastal oil and gas facilities which discharge drilling fluids and cuttings to publicly owned treatment works (POTW's), nor are any new facilities projected to direct these wastes in such manner. However, due to the high solids content of drilling fluids and cuttings, EPA is proposing to establish pretreatment standards for existing and new sources equal to zero discharge because these wastes are incompatible with POTW operations. For further discussion, see the Coastal Technical Development Document. For PSNS, zero discharge would not cause a barrier to entry for the same reasons as discussed previously under Part 6.b. of this Section.

B. Produced Water

1. Waste Characterization

Produced water is brought to the surface during the oil and gas extraction process and includes: formation water extracted along with oil and gas; injection water used for secondary oil recovery that has broken through the formation and mixed with the extracted hydrocarbons; and various well treatment chemicals added during the production and oil/water separation processes. Produced water is the highest volume waste in the coastal oil and gas industry. Depending on the age of a well and site-specific formation characteristics, the produced water can constitute between 2 percent and 98 percent of the gross fluid production at a particular well. Generally, in the early production phase of a well the produced water volume is relatively small and the hydrocarbon production makes up the bulk of the fluid. Over time, the formation approaches hydrocarbon depletion and the produced water volume usually exceeds the hydrocarbon production. Based on information received in the 1993 Coastal Oil and Gas Questionnaire, the average produced water rate from a well is approximately 1180 barrels per day (bpd) in Cook Inlet and 270 bpd in the Gulf coast. EPA estimates that 228 million barrels per year (bpy) of produced water is discharged to surface waters by the coastal oil and gas industry.

As part of this rulemaking, EPA has embarked upon a systematic effluent sampling program to identify and quantify the pollutants present in produced water, with an emphasis toward the identification of listed priority pollutants. Details of EPA's data collection activities are presented in Section V of this notice, with additional detail and sampling results discussed in the Coastal Technical Development Document. The information collected has confirmed the presence of a number of organic and metal priority pollutants in produced water.

Pollutants contained in coastal oil and gas industry produced water discharges from facilities with treatment systems used to meet the BPT level permit limits were identified as part of EPA's sampling effort. A summary of the data from these sampling activities is contained in the Coastal Technical Development Document. EPA's sampling data and the industry-supplied Cook Inlet Study identified many organic priority pollutants and all of the 13 metal priority pollutants as being present in BPT treated produced water discharges following some treatment for oil and grease (oil) removal. The priority organics most often present in significant amounts were benzene, naphthalene, phenol, toluene, 2-propanone, ethylbenzene and xylene. In addition to the priority pollutants, EPA identified total suspended solids, oil and grease, and a number of nonconventional pollutants including barium, chlorides, ammonia, magnesium, strontium and iron present in produced water.

2. Selection of Pollutant Parameters

a. Pollutants Regulated.

Where zero discharge would be required, all pollutants found in produced water discharges would be controlled. Where discharges would be allowed, *i.e.* Cook Inlet, EPA would be regulating oil and grease under BAT as an indicator pollutant controlling the discharge of toxic and nonconventional pollutants. Oil and grease would be limited under BCT as a conventional pollutant and under NSPS as both a conventional pollutant and as an indicator pollutant controlling the discharge of toxic and nonconventional pollutants.

It has been shown previously in the development of the Offshore Guidelines (See the Offshore Technical Development Document, Section VI) that oil and grease serves as an indicator for toxic pollutants in the produced water wastestream, including phenol, naphthalene, ethylbenzene, and toluene. During its development of the Offshore Guidelines, EPA showed that gas flotation technology (the technology basis for the oil and grease limitations) removes both metals and organic compounds, resulting in lower concentration levels in the discharge for the above priority pollutants (See Section IX of the Offshore Technical Development Document).

b. Pollutants Not Regulated.

The feasibility of regulating separately each of the constituents of produced water determined to be present was also evaluated during the development of the Offshore Guidelines (See Section VI of the Offshore Technical Development Document). EPA determined that it is not feasible to regulate each pollutant individually for reasons that include the following: (1) The variable nature of the number of constituents in the produced water, (2) the impracticality of measuring a large number of analytes, many of them at or just above trace levels, (3) use of technologies for removal of oil which are effective in removing many of the specific pollutants, and (4) many of the organic pollutants are directly associated with oil and grease because they are constituents of oil, and thus, are directly controlled by the oil and grease limitation. These reasons also apply to the Coastal Guidelines.

While the oil and grease limitations limit the discharge of toxic pollutants, EPA determined, during the Offshore Guidelines rulemaking, that certain of the toxic priority pollutants, such as pentachlorophenol, 1,1,-dichloroethane, and bis(2-chloroethyl) ether would not be controlled by the limitations on oil and grease in produced water. EPA is not proposing to regulate these pollutants in this rule because EPA did not detect them in the samples within the coastal oil and gas data base. (See the Coastal Technical Development Document).

3. Control and Treatment Technologies

a. Current Practice.

Based on information collected by the 1993 Coastal Oil and Gas Questionnaire as well as industry contacts, no coastal oil and gas facilities are discharging produced water in Alabama, Florida, California or Alaska's North Slope. This is due to a combination of factors including operational preference, waterflooding, and/or state requirements. In addition, the Louisiana Department of Environmental Quality issued regulations in 1992 (LAC:33,IX, 7.708) which prohibit discharges of produced water to fresh water areas characterized as ''upland'' after July 1, 1992. The regulation defines ''upland'' as ''any land not normally inundated with water and that would not, under normal circumstances, be characterized as swamp of fresh, intermediate, brackish or saline marsh''. The regulation does, however, allow discharges to the major deltaic passes of the Mississippi River and the Atchafalaya River. The same regulation also requires that discharges inland of the inner boundary of the Territorial Seas into intermediate, brackish or saline waters must either cease discharges or comply with a specific set of effluent limitations. These requirements must be met within a certain time frame, as required in the regulations, but, in most cases, no later than January 1997.

In addition, EPA proposed general NPDES permits (57 FR 60926, December 22, 1992) for production wastes which would impose a prohibition on discharges of produced water in coastal areas of Texas and Louisiana. These permits were finalized January 9, 1995 (60 FR 2387). The permits would not, however, apply to facilities treating offshore waters and discharging into the main passes of the Mississippi and Atachafalaya River. Based on these permits requiring zero discharge, only Alaska's Cook Inlet and two sites in the Gulf of Mexico would be discharging produced water in the Coastal subcategory at the time this final rule is scheduled to be signed, currently July 1996.

The current BPT regulations established for the coastal subcategory limit the oil and grease content in the discharged produced water. Existing technologies for the removal of oil and grease include gravity separation, gas flotation, heat and/or chemical addition to assist oil-water separation, and filtration. Methods for the discharge or disposal of produced water from facilities in the coastal subcategory include free fall discharge to surface waters, discharge below the water surface, use of channels to convey the discharge to water bodies, and injection via regulated Class II Underground Injection Control (UIC) wells into underground formations. As an alternative, a number of production sites transport produced water by pipeline, truck or barge to shore facilities for disposal in UIC Class II wells. At times, this transport consists of the gross fluid produced and the oil-water separation takes place at the off-site facility.

While sampling data has indicated quantifiable reductions of naphthalene, lead, and ethylbenzene by BPT treatment (*i.e.*, by oil-water separation technology), this data also demonstrates the presence of significant levels of priority pollutants remaining in the treated effluent.

b. Additional Technologies.

In developing the proposed regulation, EPA evaluated several treatment technologies for application to the produced water wastestream. These technologies were considered for implementation at the coastal production sites and at the shore facilities where much of the produced water is currently treated for subsequent discharge to coastal subcategory waters.

(1) Improved Gas Flotation.

Gas flotation is a treatment process that separates low-density solids and/or liquid particles (*e.g.*, oil and grease) from liquid (e.g., water) by introducing small gas (usually air) bubbles into wastewater. As minute gas bubbles are released into the wastewater, suspended solids or liquid particles are captured by these bubbles, causing them to rise to the surface where they are skimmed off.

EPA considered as an option using gas flotation technology with chemical addition as a basis for improving BPT-level performance. This option would require all coastal discharges of produced water to comply with oil and grease limitations of 29 mg/l monthly average and a daily maximum of 42 mg/l. The technology basis for these limitations is improved operating performance of gas flotation technology. EPA has determined that gas flotation systems could be improved to increase removal efficiencies—*i.e.*, the amount of pollutants removed. Specific mechanisms include proper sizing of the gas flotation unit to improve hydraulic loading (water flow rate through the equipment), adjustment and closer monitoring of engineering parameters such as recycle rate and shear forces that can affect oil droplet size (the smaller the oil droplet, the more difficult the removal), additional maintenance of process equipment, and the addition of chemicals to the gas flotation unit. (See Offshore Technical Development Document Section IX).

The addition of chemicals can be a particularly effective means of increasing the amount of pollutants removed. Because the performance of gas flotation is highly dependent on ''bubble-particle interaction,'' chemicals that enhance that interaction will increase pollutant removal.

Gas flotation is a technology which has been used for many years in treating produced water in the offshore subcategory. In developing final effluent limitations guidelines and standards for the offshore subcategory (58 FR 12454; March 4, 1993), EPA evaluated comments and data submitted by the industry which strongly urged EPA to select improved gas flotation technology as the basis for BAT limits and NSPS, based on an Offshore Operator Committee's (OOC's) 83 Platform Composite Study. Industry further noted that chemical additives would improve the amount of oil and grease in produced water that could be removed. EPA thoroughly reviewed these comments and additional data, and agreed with industry that improved gas flotation should be used as the technology for setting BAT limits and NSPS in the offshore subcategory.

In establishing BAT limits and NSPS for produced water, EPA evaluated the effluent data from the platforms in the 83 Platform Composite Study identified as using improved gas flotation (*e.g.*, use of gravity separators and chemical additives). First, EPA modeled the offshore platform with ''median'' oil and grease effluent values (i.e., 50 percent of the platforms in the database had oil and grease effluent values above (and 50 percent below) the median of the effluent values measured at the median platform. Based on the oil and grease measured at the median platform after improved gas flotation treatment, and allowing for average ''within-platform'' variability, EPA set a daily maximum limit on oil and grease at 42 mg/l, and a 30-day average of 29 mg/l as the BAT limits and NSPS. (See 58 FR 12462, March 4, 1993).

In setting BAT limits and NSPS for the offshore rule, EPA had a choice among several different means of measuring what is termed ''oil and grease'' in produced water, two of which are known as Method 413.1 and Method 503E.

Under Method 413.1, freon is mixed with a sample of produced water. The container is then left at rest to separate the water phase from the freon phase, which includes those contaminants in produced water that dissolve in freon. The freon layer is then drained from the container and distilled by heating, leaving a residue. The residue is then weighed and reported as the weight of the ''oil and grease'' in that sample of produced water. The results are typically reported in milligrams of oil and grease per liter of produced water.

Under Method 503E the same steps are followed, with one exception. After the freon layer is drained from the container, but prior to distillation, silica gel is added to the freon, and weighed. Because the silica gel has the ability to adsorb polar materials (*e.g.*, some of the hydrocarbons and fatty acids present) that otherwise would have been measured as oil and grease in the freon residue by Method 413.1, the analytical result reported under Method 503E is less than that reported under Method 413.1. Because Method 413.1 measures more of the oil and grease in produced water, it gives a more complete picture of the efficiency of the treatment system. Because EPA had influent and effluent data showing that oil and grease, measured under Method 413.1, were removed by the use of improved gas flotation (Oil Content in Produced Brine on Ten Louisiana Production Platforms, September 1981) R.I.G. (No. 194), EPA used improved gas flotation as the technology basis for the rule and established the limitations as measured by Method 413.1 (See also Final Report, Analysis of Oil and Grease Data Associated with Treatment of Produced Water by Gas Flotation Technology, January 13, 1993, and 58 FR 12462, March 4, 1993).

(2) Filtration.

The primary purpose of filtration is to remove suspended matter, including insoluble oils, from produced water. Additional removal of soluble pollutants can also be achieved, but it is not as significant as the reduction of conventional pollutants such as total suspended solids and oil and grease. EPA has considered several types of filtration systems as part of this rulemaking, including granular, membrane and cartridge filtration technologies. EPA's assessment of granular filtration is based in part on data collected from a coastal oil and gas facility as part of the offshore subcategory rulemaking (Three Facility Study). Although economically achievable, granular filtration was rejected as the technology basis for controlling discharges in this proposed rule. EPA's evaluation of granular filtration performance data indicates that while this technology does provide some removals of priority and nonconventional pollutants, the pollutant removal efficiency of granular filtration (in the range of 46–68 percent oil and grease removal) is generally not as effective as that attainable through improved operation of gas flotation technology (general oil and grease removal efficiency have been shown to be 90–95 percent). In addition, the capital and annual operating and maintenance costs associated with granular filtration are significantly higher than the costs of improving gas flotation systems.

EPA did not select membrane filtration as a technology basis for this proposed rule because it has not been sufficiently demonstrated as available to support national effluent limitations at this time. Membrane filtration is a commercially demonstrated technology in other industries and several manufacturers have been developing this technology for use in treating produced water. Although not yet available to the oil and gas industry, some operators have shown interest in the technology and limited testing of these systems has taken place. In developing the final limitations for the offshore subcategory, EPA determined that because of operational problems (e.g., fouling of the membrane, actual treatment capacity less than design capacity) this technology did not support use as a technology basis for final effluent limitations. (See 58 FR 12481; March 4, 1993.) In the absence of any data to the contrary, EPA believes that this technology still is not available for full-scale systems capable of long-term, effective treatment of produced water.

In evaluating reinjection of produced water, EPA noted that a number of coastal oil and gas sites were using cartridge filters as part of the treatment system. EPA collected wastewater samples to characterize the efficacy of cartridge filtration to determine whether this technology should serve as a basis for effluent limitations and standards. EPA's evaluation of cartridge filtration performance data indicates that this technology is capable of providing oil and grease removal only marginally better than that currently required by the existing BPT effluent limitations. In addition, EPA's evaluation did not identify any significant removals of the priority and nonconventional pollutants present in produced water. Thus, cartridge filtration was not selected as a basis for limiting produced water discharges.

3. Injection

EPA also considered using injection technology as a basis for setting a more stringent requirement under this rule. With the exception of Cook Inlet, injection of produced water is widely practiced by facilities in the coastal subcategory as well as in the onshore subcategory. Injection technology for produced water consists of injecting it, under pressure, into Class II UIC wells into underground formations. This option results in no discharge of produced water to surface waters.

Treatment of the produced water prior to injection is usually necessary, and such treatment often includes removal of oil and suspended matter by BPT oil separation technology followed by filtration technology. The removal of suspended matter prior to injection is required to prevent pressure build-up and plugging of the receiving formation and/or to protect injection pumps from damage.

While EPA determined that filtration was not a technology appropriate for serving as the basis for control of effluent prior to discharge, filtration was considered relevant technology for use as pretreatment prior to injection, thus, it is included as part of the basis for the injection technology option. EPA determined from information gathered on site visits in the Gulf coast area, as well as from industry contacts, that cartridge filtration is generally used following BPT oil/water separation technologies at injecting facilities accessible by water only. For facilities accessible by land, it was determined that rather than pretreat produced water using filtration, it is more cost effective to perform periodic well workovers on the injection well to remove clogged material from the wellbore. However, for facilities treating produced water flows greater than 64,000 bpd, EPA determined that it would be more appropriate to employ granular filtration after BPT separation technology because it is more cost effective to use this technology for higher flows rather than cartridge filtration.

4. Other Technologies

In developing effluent limitations for the offshore subcategory, EPA also considered other technologies such as carbon adsorption, biological treatment, chemical precipitation, and hydrocyclones. (See 56 FR 10688; March 13, 1991.) Carbon adsorption was rejected as a technology basis because the limited use of this technology did not give sufficient performance data to enable a full evaluation. Biological treatment was rejected because of problems associated with biologically treating the high dissolved solids (brine) waters. Operational problems and an inability to quantify reductions of priority pollutant metals led to rejection of chemical precipitation. Hydrocyclones were rejected as a technology basis for BAT/NSPS effluent limits because the performance data available demonstrated only that it was capable of meeting existing BPT limits for oil and grease, and data were lacking regarding removals of priority pollutants. EPA has not received any new information regarding treatment efficacy (as measured by priority pollutant removal) for these technologies, and is not aware of any information which would support conclusions different than those made for the Offshore Guidelines.

5. Options Considered

Five options were considered by EPA in developing BCT, BAT, NSPS, PSES and PSNS limitations for produced water. These options were based on either injection, improved gas flotation, or a combination of these technologies. The 5 options are listed below with limitations for oil and grease associated with the options allowing discharges:

Option 1—(BPT All): EPA has included as an option setting effluent limitations equal to the existing BPT requirements. Oil and grease would be limited in the effluent at 48 mg/l monthly average, and 72 mg/l daily maximum.

Option 2—(Improved Flotation All): All discharges of produced water would be required to meet limitations on oil and grease content of 29 mg/l 30-day average and a daily maximum of 42 mg/l. The technology basis for these limits is improved operating performance of gas flotation. The specific numerical limit of 29 mg/l 30-day average and 42 mg/l (daily maximum) are based on the statistical analyses of performance of improved gas flotation conducted to develop oil and grease limits for the Offshore Guidelines. (See 58 FR 12462, March 4, 1993).

Option 3—(Zero Discharge; Cook Inlet BPT): With the exception of facilities in Cook Inlet, all coastal oil and gas facilities would be prohibited from discharging produced water. Coastal facilities in Cook Inlet would be required to comply with existing BPT effluent limitations (48/72 mg/l described above) for oil and grease.

Option 4—(Zero Discharge; Cook Inlet Improved Flotation): With the exception of facilities in Cook Inlet, all coastal oil and gas facilities would be prohibited from discharging produced water. Coastal facilities in Cook Inlet would be required to comply with the oil and grease limitations of 29 mg/l 30-day average and 42 mg/l daily maximum based on improved operating performance of gas flotation and the statistical analysis conducted for the Offshore Guidelines.

Option 5—(Zero Discharge All): This option would prohibit all discharges of produced water based using injection.

Specific alternatives have been developed for Cook Inlet to account for the different operational practices, and geological situations that exist at these platforms. As previously stated, zero discharge is widely, if not exclusively, practiced in all coastal areas except Cook Inlet. Injection of produced waters is not practiced in Cook Inlet because, where waterflooding is occurring, treated seawater is injected instead. Industry claims that injection of seawater other than produced water for enhanced recovery is practiced primarily because injection of produced water would cause formation fouling. Industry has claimed that fouling would occur due to bacteria and scale formation in produced water, and otherwise not present in seawater. EPA has determined that formation fouling problems associated with produced water injection are not insurmountable because filtration and anti-fouling chemicals can be added prior to injection, and periodic downhole workovers can be performed to reopen clogged formation surfaces.

An additional problem with injecting produced waters is that no other formations exist that can accommodate this wastestream other than the producing formation. Cook Inlet operators would experience significant additional cost associated with piping produced water if zero discharge was required from where it is currently treated to where it could be injected. Of the 13 producing platforms in the Inlet, 9 of them currently direct their extracted hydrocarbon fluids to one of 3 land-based separation and treatment facilities. These land-based facilities separate the hydrocarbons from the produced water, treat the produced water and then discharge it in accordance with EPA's Region X's NPDES general permit requirements. The Alaska Oil and Gas Conservation Commission has confirmed that no geological formations exist beneath the land-based facilities that are large enough to accept the approximately 100,000 barrels per day (bpd) of produced water generated from these facilities. Thus, produced water would be piped back to the platforms for injection if produced water discharges were prohibited. The costs for such piping would comprise 74 percent of the total costs for injection. This would be a major cost factor for the Inlet operations overall since the volume of produced water being discharged from these 3 land-based facilities amounts to approximately 99 percent of that discharged from all 13 platforms.

6. BCT Options

a. BCT Methodology.

The methodology to determine the appropriate technology option for BCT limitations is previously described in Section VI.A.

b. BCT Cost Test Calculations and Option Selection.

The five options previously described, were evaluated according to the BCT cost reasonableness tests. The pollutant parameters used in this analysis were total suspended solids and oil and grease. All options, except the ''BPT All'' option, fail the BCT cost reasonableness test and thus, EPA proposes to establish BCT limitations equal to BPT. Costs for the ''BPT All'' option are equal to zero because facilities are complying with the current BPT limitations. The range of the results for the POTW test (first part of the BCT cost test) for the other options is $1.35 to $3.70 per pound of conventional pollutant removed. Since a value of less than $0.53 per pound (1992$) is required to pass the POTW test these four options fail the first BCT cost test. Thus, EPA is proposing to establish the BCT limitations for produced water equal to BPT (48 mg/l monthly average; 72 mg/l daily maximum). The calculations for BCT cost reasonableness test for the produced water options are described in more detail in Section XI of the Coastal Technical Development Document. There are no incremental non-water quality environmental impacts associated with the BCT option because it is equal to BPT.

7. BAT and NSPS Options

EPA has selected Zero discharge; Cook Inlet improved gas flotation (Option 4) for the BAT and NSPS level of control for produced water. A discussion of the cost and impacts and a description of the selection rationale is contained below:

a. Costs.

The cost and pollutant removals associated with the options considered for BAT are presented in Table 5.

TABLE 5.—COSTS AND POLLUTANT REMOVALS FOR PRODUCED WATER BAT OPTIONS

Option	Costs (1992$) (x1000)	Pollutant removals (lbs) (x1000)
1. BPT all	0	0
2. Improved gas flotation all	12,400	12,440
3. Zero discharge; cook inlet BPT	28,600	4,306,800
4. Zero discharge; cook inlet improved gas flotation	30,860	4,308,300
5. Zero discharge all	49,700	5,484,800

These estimates are presented incremental to the baseline of current industry operating practices which is equal to BPT where discharges are occurring. Thus, as shown on Table 5, costs attributable to Option 1, which is equal to BPT, is zero. On January 9, 1995 (60 FR 2387), EPA promulgated general NPDES permits that would prohibit discharges of produced water from coastal facilities in Texas and Louisiana. For the purpose of this proposal, EPA's compliance cost estimates and economic impact assessments are determined without considering this permit. Had EPA's costing estimates assumed that the general permit would be in effect, the total estimated cost of the proposed BAT limitations for produced water for the entire coastal subcategory would be $10.4 million instead of $30.9 million annually.

In developing the costs of zero discharge for this option, EPA determined, based on Texas and Louisiana state permit data, the number and volume of produced water discharges that would be discharging by the time this final rule is scheduled to be signed July 1996. This investigation identified, by operator and oil and gas field, 216 produced water separation/ treatment facilities that would be discharging approximately 180 million barrels per year (bpy) in Texas and

Louisiana as of July 1996. Costs are calculated without taking into account the regulatory effects of the zero discharge requirement imposed by the EPA Region VI General Permits (See Section II.C. of this preamble).

In determining the costs associated with zero discharge for the Gulf coast area, EPA utilized the following factors in the costing analyses:

General

* The only areas that will incur compliance costs are Cook Inlet in Alaska, Texas, and parts of Louisiana since all other coastal areas that have oil and gas activities currently practice zero discharge.

For Texas and Louisiana

* Produced water would be injected into Class II UIC injection wells. The capacity of each Class II injection well is 5,000 BPD.

* 90 percent of the injection wells would be converted from previously producing wells or dry holes.

* If a discharge is greater than 108 bpd (for water-based facilities) and 71 bpd (for land-based facilities), then the produced water would be injected onsite; if the discharge is less than those flows then it would be more cost effective to send the produced water offsite to a commercial facility for injection. (EPA's data from Texas and Louisiana coastal permits show that 77 percent of the produced water discharges would inject on-site).

* For purposes of estimation, all Texas separation/treatment facilities are located on land and all Louisiana separation/treatment facilities are located over water. EPA is aware that this is not entirely the case, *i.e.* some facilities in Louisiana are located over land and some Texas facilities are located over water. In the absence of specific location information on all of the 216 discharging facilities, EPA determined this to be a good approximation since the coastal topography of Louisiana consists of more extensive wetlands than that of Texas. (Location is an important factor when determining the cost of drilling an injection well, and the cost of produced water transportation. EPA's state permit data base shows that 24 percent of the produced water discharges are in Texas and the separation/treatment facilities are therefore considered to be on land).

* No pretreatment beyond BPT technology is required prior to injection for land-based facilities because it is more cost effective to perform downhole well workovers twice a year. Pretreatment beyond BPT treatment prior to injection consists of cartridge filtration for water-based facilities. For flows greater than 64,000 bpd, granular filtration is used as pretreatment.

* Capital costs are based on sizing equipment to accommodate future produced water volume, estimated to be approximately 1.5 times current flow.

* Where more than one produced water discharge location exists from one or more production facilities owned by the same operator in the same field, EPA combined the discharges to be injected into a single injection system. By combining discharges a savings would result due to installation of fewer injection wells.

For Cook Inlet

* No geological formations are available for produced water injection except the producing formations.

* No geological formations are available near or below the existing onland separation/treatment facilities. Thus, the produced waters would be required to be piped back to the platforms for injection.

* Pretreatment prior to injection consists of gas flotation and multimedia filtration. However, operators will use existing equipment where it currently exists, and no costs would be incurred for such existing equipment.

* During the development of this proposal, industry provided EPA with information on reservoir plugging and souring that may result from injecting produced water in the Cook Inlet. EPA, in its cost analysis, included costs for the addition of chemicals that would be added to the produced water being injected to alleviate the scaling and hydrogen sulfide (H2S) formation problems associated with injection in this area. Such chemicals include biocides and scale inhibitors. Annual workovers must also be performed on the injection wells.

EPA believes that the cost estimates are conservative for a number of reasons. As discussed previously, EPA determined costs to comply with a zero discharge requirement in the Gulf of Mexico based on the number of facilities that would be discharging after the expected date of promulgation for this rule (July 1996). A total of 216 facilities would still be discharging by then. However, 28 of these facilities in Louisiana will be required to cease discharging by January 1, 1997, because of the state water quality standard's no discharge requirement. Taking this January 1997 requirement into account as a portion of the baseline would further reduce costs by 25 percent.

Furthermore, EPA's cost estimates for zero discharge in the Gulf of Mexico are based on sizing produced water treatment equipment to accommodate future produced water volumes estimated to be approximately 1.5 times current flow. EPA believes using this factor, which is standard engineering practice, has resulted in a conservative cost estimate overall because many operators have indicated that they typically use a factor of 1.2 to 1.25 when sizing and costing produced water treatment equipment. Capital costs would be approximately 12 percent lower if a factor of 1.2 were used. Additionally, while EPA's costing included combining of operator discharges for injection within fields, the analysis showed that costs are not significantly different if they are not combined. This is because the high costs of piping to join discharges closely equal the costs of individual injection well installation.

EPA also calculated capital costs of produced water treatment on the basis that produced water flows increase the same for oil as for gas wells. While produced water volumes from gas producing wells will generally not increase at the rate of 1.5, EPA did not differentiate between the two.

EPA determined that no costs would be attributed to zero discharge for California, Florida, Alabama, certain parts of Louisiana, and the North Slope of Alaska because operators in these areas are already practicing zero discharge of all produced waters.

For improved gas flotation, costs were estimated based on an evaluation of this technology during development of the Offshore Guidelines (58 FR 12463). Improved performance of gas flotation units includes improved operation and maintenance of gas flotation treatment systems and chemical pretreatment to enhance system effectiveness. Costs are based on vendor-supplied data, industry information, cost analyses conducted by the Department of Energy, and EPA projections. Capital and O & M costs were applied specifically to the coastal oil and gas operations using nine modeled flows for land- and water-access production facilities. From these nine modeled flows, EPA conducted regression analyses to derive cost equations that would vary based on flow. These equations were then applied to the actual 216 discharging facilities to estimate costs on a site specific basis. Capital costs include equipment purchase, installation, and platform or concrete pad (for land based operations) retrofit. Operation and maintenance costs are estimated to be 10 percent of capital costs.

EPA solicits comments on these costs and also information regarding the longitude and latitude locations of discharging produced water separation/treatment facilities in Texas.

The total annual cost of Option 4 for BAT control of produced water discharges from existing facilities is estimated at $30.9 million (1992 dollars) for the entire coastal subcategory. $29.2 million of this total would be incurred by operators in the Gulf Coast states of TX and LA in attaining zero discharge. The remaining $2.3 million would be incurred by Cook Inlet operators in complying with the oil and grease limitations. EPA finds this cost to be economically achievable for the reasons discussed later in Section VII of this preamble but are briefly summarized here. Total production losses realized from this option are expected to total 15.2 million bbls over the lifetime of the wells and platforms subject to this rule which equals up to 1.7 percent of total lifetime production for the Gulf and Cook Inlet combined. The net present value losses of producer income associated with this decrease in production is $153.2 million. A total of 111 wells in the Gulf coast area (2.4 percent of all current Gulf coast wells) and no Cook Inlet platforms are considered likely to shut in immediately when this proposal becomes final. Furthermore, a maximum of 12 Gulf operators might fail as a result of this BAT option (2.8 percent of the current Gulf operators). No company failures are expected in Cook Inlet. This option would reduce the pollutant loading from this wastestream by 4.3 billion pounds per year.

c. Rationale for Selection of BAT.

EPA proposes Zero Discharge; Cook Inlet Improved Gas Flotation Option 4: as BAT for produced water. This option prohibits discharges of produced water from all coastal facilities, except for those facilities located in Cook Inlet. Coastal facilities in Cook Inlet would be required to comply with the oil and grease limitations (29 mg/l 30-day average, 42 mg/l daily maximum) based on improved operating performance of gas flotation. EPA has determined this option to be economically achievable and technologically available, and that it reflects the BAT level of control.

Zero discharge is technologically available because injection of produced water is currently ongoing in much of the coastal subcategory at the present time and adequate geological formations exist to accept produced water. By 1996, 72 percent of the facilities in the Gulf region will be meeting zero discharge. The oil and grease limit applicable to Cook Inlet is technologically available for the reasons discussed elsewhere in this preamble, the record for this rule, as well as in cited portions of the rulemaking record for the Offshore Guidelines.

Option 4 is economically achievable because, as the economic analysis shows (in Section VII), total production losses in terms of oil production as a result of this proposed rule are expected to range between 1.0 percent and 1.7 percent of total lifetime production for both Cook Inlet and the Gulf. Additionally, only 2.4 percent of all current Gulf coastal wells (111 out of 4675 current Gulf coastal wells) and no Cook Inlet platforms are considered likely to shut in as a result of this rule. These shut-in wells tend to be relatively low-producing and marginal wells. At most, only 2.8 percent of the operators in the Gulf (12 of the estimated 435 Gulf coastal operators) might fail as a result of a zero discharge requirement and no firm failure is expected in Cook Inlet, as a result of meeting oil and grease limits of 29 mg/l 30-day average and 42 mg/l daily maximum for produced water. (The range of firm failures in the Gulf is actually 0-12, but because data were not available to rule out the possibility of failures, EPA assumed possible failures to be actual failures.) The ‘‘average’’ Gulf coastal firm does not discharge produced water and coastal firms are expected to face average (medium) declines in equity or working capital of 0 percent. Of the 122 discharging firms, average (medium) declines in equity or working capital of 0.37 percent and 2.63 percent, respectively, are expected to occur. These impacts, combined with the fact that most Gulf coastal operators (72 percent) will not be discharging by 1996, show Option 4 to be economically achievable.

Option 5, zero discharge all was not selected based on the unacceptable economic impacts estimated for the Cook Inlet operators. EPA's economic analysis shows that 3 of 13 platforms would be ‘‘shut-in’’ or closed down and believes that this economic impact is unacceptable in Cook Inlet. EPA did not select the ‘‘Flotation All’’ or ‘‘BPT All’’ options as preferred because they, applied industry-wide, do not represent BAT or NSPS level of control. As stated previously, all coastal operations in California, Alabama, Florida, some parts of Louisiana and the North Slope of Alaska do not discharge produced water, but inject their produced water underground either to comply with permit limitations or to enhance hydrocarbon recovery. EPA has therefore concluded that control options based on the continued discharge of produced water in all areas of the country do not represent BAT or NSPS. Non-water quality environmental impacts for the proposed Option 4 consist of incremental air emissions of approximately 2800 tons/year across the entire subcategory. Given that an average Gulf coast production facility may alone produce approximately 188 tons/year of emissions, this option would increase air emissions by about 13 percent. EPA considers this increase to be acceptable. A description of estimated non-water quality impacts, consisting of additional energy requirement and air emission created by complying with the proposed requirements and other options being considered are discussed in Section VIII of this preamble and in more detail in Chapter XIV of the Coastal Technical Development Document.

d. Rationale for Selection of NSPS.

For NSPS control of produced water discharges from new sources, EPA is proposing the ‘‘Zero Discharge All’’ (Option 5) prohibiting discharges of produced water from all new sources. Option 5 is economically achievable for the reasons discussed in the economic impact analysis and in Section VII, below. This NSPS option is estimated to cost approximately $4.5 million annually for the entire coastal subcategory. This cost would be incurred only by Gulf Coast operators where EPA estimates that approximately 6 new production facilities will be constructed per year. No new sources are expected in the Cook Inlet (See Section VII). However, were new sources to be installed in Cook Inlet, the preferred NSPS option of zero discharge is not expected to cause a barrier to entry because new project operations would still be quite profitable. For a new source, EPA estimates that the decline in internal rates of return would only be reduced from 39 to 37 percent and therefore would not be likely to affect the decision to undertake a new project. In addition, the impact on Net Present Value from the zero discharge requirement (2.9 percent) is not substantially different from the impacts on Net Present Value from the proposed BAT option for Cook Inlet platforms (2.4 percent). Thus existing and new platforms would face similar impacts on Net Present Value and Internal Rate of Return. In addition, as discussed in Section VIII, EPA has determined the non-water quality environmental impacts to be acceptable for the NSPS option for produced water. Total incremental emissions from the proposed option is approximately 64 tons/year for NSPS. As a comparison, an average Gulf coast production facility may produce approximately 188 tons/year of emissions. EPA considers this increase in non-water quality impacts to be acceptable.

8. PSES and PSNS Options Selection

Based on the 1993 Coastal Survey and other information reviewed as part of this rulemaking, EPA has not identified any existing coastal oil and gas facilities which discharge produced water to publicly owned treatment works (POTWs), nor are any new facilities projected to direct their produced water discharge in such manner. However, because EPA is proposing a limitation requiring zero discharge for those existing facilities, there is the potential that some facilities may consider discharging to POTWs in order to avoid the BAT and /or NSPS limitations. Pretreatment standards for produced water are appropriate because EPA has identified the presence of a number of toxic and nonconventional pollutants, many of which are incompatible with the biological removal processes at POTWs. Large concentrations of dissolved solids in the form of various salts in the produced water cause the discharge to POTWs to be incompatible with the biological treatment processes because these ''brines'' can be lethal to the organisms present in the POTW biological treatment systems. (See the Coastal Technical Development Document for detailed information on produced water characterization.) EPA does not have sufficient data for conducting a pass through analysis for reasons discussed further in the Coastal Technical Development Document. EPA solicits data and comment on this particular issue.

EPA is proposing to require pretreatment standards for existing and new sources (PSES and PSNS, respectively) that would prohibit the discharge of produced water. The technology basis for compliance with PSES and PSNS would be the same as that for BAT and NSPS zero discharge limits. The cost projections for both PSES and PSNS are considered to be zero since no existing sources discharge to POTW's and there are no known plans for new sources to be installed in locations amenable to sewer hookup. Also, because no facilities are discharging to POTW's EPA proposes that PSES and PSNS requiring zero discharge be effective as of the effective date of this rule. Because zero discharge for new sources is economically achievable, the costs of complying with zero discharge would not be a barrier to entry. Non-water quality environmental impacts would be similar to those for new sources, which EPA has found to be acceptable. Thus, EPA has determined that pretreatment standards for new sources that are equal to NSPS are economically achievable and technologically available for PSNS and that the non-water quality environmental impacts are acceptable.

C. Produced Sand

1. Waste Characterization

Produced sand consists primarily of the slurried particles that surface from hydraulic fracturing and the accumulated formation sands and other particles (including scale) generated during production. Produced sand is generated during oil and gas production by the movement of sand particles in producing reservoirs into the wellbore. The generation of produced sand usually occurs in reservoirs comprised of geologically young, unconsolidated sand formations. The produced sand wastestream is considered a solid and consists primarily of sand and clay with varying amounts of mineral scale and corrosion products. This waste stream may also include sludges generated in the produced water treatment system, such as tank bottoms from oil/water separators and solids removed in filtration.

Produced sand is carried from the reservoir to the surface by the fluids produced from the well. The well fluids stream consists of hydrocarbons (oil or gas), water, and sand. At the surface, the production fluids are processed to segregate the specific components. The produced sand drops out of the fluids stream during the separation process and accumulates at low points in equipment. Produced sand is removed primarily during tank cleanouts. Because of its association with the hydrocarbon stream during extraction, produced sand is generally contaminated with crude oil or gas condensate.

Produced sand samples were obtained during EPA's sampling visits to 10 production facilities. Analysis of these samples showed oil and grease concentrations of 205 g/Kg. All toxic metals were present except silver, with most notable contributions from copper (32.15 mg/Kg) and lead (171.94 mg/Kg). Naturally Occurring Radioactive Material (NORM) was present at an average of 8.9 pCi/g in the samples which were taken from coastal facilities in the Gulf of Mexico. Toxic organics present were similar to those found in produced water including benzene, ethylbenzene, xylene, toluene, propanone and phenanthrene. All 10 sites disposed of the produced sands at commercial facilities. Produced sand volumes vary from well to well and are a function of produced water production, formation type, and well completion methods. Maximum produced sand volumes (out of these 10 sites) was 400 bpy per production facility. The 1993 Coastal Survey results showed that average volumes of produced sand ranged from 36 to 94 bpy per facility. Additional discussion of produced sand is presented in the Coastal Technical Development Document.

2. Selection of Pollutant Parameters

EPA is proposing to control all pollutants present in produced sand by prohibiting discharge of this wastestream.

3. Control and Treatment Technologies

No effluent limitations guidelines have been promulgated for discharges of produced sand in the coastal subcategory. The final NPDES permits for Texas, Louisiana, and the existing state NPDES permits for Alabama contain a zero discharge limit for produced sand.

Data from the 1993 Coastal Oil and Gas Questionnaire indicate that the predominant disposal method for produced sand is landfarming, with underground injection, landfilling, and onsite storage also taking place to some degree. Because of the cost of sand cleaning, in conjunction with the difficulties associated with cleaning some sand sufficiently to meet existing permit discharge limitations, operators use onshore (onsite or offsite) or downhole disposal. In fact, only one operator was identified in the 1993 Coastal Oil and Gas Questionnaire as discharging produced sand in the Gulf of Mexico, but this operator also stated that it planned to cease its discharge in the near future. All Cook Inlet operators submitted information stating that no produced sand discharges are occurring in this area.

4. Options Considered and Rationale for Options Selection

The only option considered is zero discharge of produced sands. Because current industrial practice for the coastal subcategory is predominately zero discharge, EPA considered this the appropriate option for this wastestream. The zero discharge requirement would eliminate the discharge of toxic pollutants present in produced sand. Because the industry practice of zero discharge is already so widespread, the zero discharge limitation will result in minimal increased cost to the industry.

EPA is proposing to set BPT, BCT, BAT and NSPS equal to zero discharge for produced sand. EPA has determined that zero discharge reflects the BPT, BCT, BAT and NSPS levels of control because, as it is widely practiced throughout the industry, it is both economically achievable and technologically available. Zero discharge for NSPS would not cause a barrier to entry because, since it is equal to current practice, it will impose no cost. Zero discharge will have negligible economic impacts on the industry. As zero discharge reflects current practice, there are negligible incremental non-water quality environmental impacts from this option. Since proposed BCT would be set equal to the proposed BPT, there is no cost of BCT incremental to BPT. Therefore, this option passes the BCT cost reasonableness tests.

The technology basis for compliance with PSES and PSNS is the same as that for BAT and NSPS. EPA proposes pretreatment standards for produced sands equal to zero discharge because, like drilling fluids and cuttings, their high solids content would interfere with POTW operations. Because EPA is not aware of any produced sands being sent to POTWs, this requirement is not expected to result in operators incurring costs. Zero discharge for PSNS would not cause a barrier to entry for the same reasons as discussed above for NSPS. There are no additional non-water quality environmental impacts associated with this requirement because it reflects current practice.

D. Deck Drainage

1. Waste Characterization

Deck drainage consists of contaminated site and equipment runoff due to storm events and wastewater resulting from spills, drip pans, or washdown/cleaning operations, including washwater used to clean working areas. Deck drainage is generated during both the drilling and production phases of oil and gas operations. Currently, approximately 11.5 million bpy of deck drainage are discharged by facilities in the coastal subcategory. EPA estimates that 112,000 pounds of oil and grease are discharged in this wastestream annually. In addition to oil, various other chemicals used in drilling and production (actual hydrocarbon extraction) operations may be present in deck drainage. Limited treated effluent data are available for this wastestream, however, EPA has identified the presence of organic and metal priority pollutants in deck drainage. EPA's analytical data for deck drainage comes from the data acquired during the development of the Offshore Guidelines. EPA conducted a three facility sampling program (described in Section V of the Offshore Technical Development Document) during which samples were taken of untreated deck drainage. Eight of the toxic metals were detected, most notably lead (ranging in concentration from 25 - 352 ug/l) and zinc (ranging in concentration from 2970–6980 ug/l). Priority organics were also present including benzene, xylene, naphthalene and toluene. Other nonconventional pollutants found in deck drainage include aluminum, barium, iron, manganese, magnesium and titanium.

The content and concentrations of pollutants in deck drainage can also depend on chemicals used and stored at the oil and gas facility. An additional study on deck drainage from Cook Inlet platforms, reviewed during development of the Offshore Guidelines, showed that discharges from this wastestream may also include paraffins, sodium hydroxide, ethylene glycol, methanol and isopropyl alcohol. (Dalton, Dalton, and Newport, Assessment of Environmental Fate and Effects of Discharges from Oil and Gas Operations, March 1985.)

2. Selection of Pollutant Parameters

EPA has selected free oil as the pollutant parameter for control of deck drainage. The specific conventional, toxic and nonconventional pollutants found to be present in deck drainage are those primarily associated with oil, with the conventional pollutant oil and grease being the primary constituent. In addition, other chemicals used in the drilling and production activities and stored on the structures have the potential to be found in deck drainage. EPA believes that an oil and grease limitation together with incorporation of site specific Best Management Practices, as required under the stormwater program and as discussed below, will control the pollutants in this wastestream.

The specific conventional, toxic, and nonconventional pollutants controlled by the prohibition on the discharges of free oil are the conventional pollutant oil and grease and the constituents of oil that are toxic and nonconventional pollutants (see previous discussion in Section VI.B. describing the chemical constituents of oil). EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitation on free oil in deck drainage reflects control of these toxic pollutants at the BAT and BADCT (NSPS) levels.

3. Control and Treatment Technologies

a. Current Practice.

BPT limitations for deck drainage prohibit the discharge of free oil. All equipment and deck space exposed to stormwater or washwater are surrounded with berms or collars. These berms capture the deck drainage where it flows through a drainage system leading to a sump tank. Initial oil/water separation takes place in the sump tank which is generally located beneath the deck floor or underground at land-based operations. Effluent from the sump tank may be directed to a skim pile, where additional oil/water separation occurs. (The skim pile is essentially a vertical bottomless pipe with internal baffles to collect the separated oil.)

The deck drainage treatment system is a gravity flow process, and the treatment tanks generally do not require a power source for operation. Thus, deck drainage generated at operations located in powerless, remote situations, (such as satellite wellheads) can be effectively treated.

The difficulties in obtaining a representative sample of deck drainage effluent (due to their submerged or underground location) preclude the use of the static sheen test for this wastestream. Thus, free oil is measured by the visual sheen test. Deck drainage treatment is discussed in more detail in the Coastal Technical Development Document.

b. Additional Technologies Considered.

EPA knows of no additional technologies for the treatment of deck drainage. However, EPA, as described in the proceeding section, has determined that deck drainage could in some circumstances be commingled with either produced water or drill fluids and thus, could become subject to the limitations imposed on these major wastestreams. EPA has also considered requiring best management practices (BMPs) on either a site-specific basis or as part of the Coastal Guidelines (See discussion under part 6.b. in this Section).

4. Options Considered

EPA has developed two options for the control of deck drainage. These are (1) establish limitations equal to BPT; or (2) establish limitations for the ‘‘first flush’’ of deck drainage equal to those for the major wastestreams it can be commingled with, and limitations equal to BPT after the first flush.

In addition to BPT technology described above, EPA examined additional treatment control options based on current industrial practices. The 1993 Coastal Oil and Gas Questionnaire as well as the industry site visits reveal that deck drainage is often commingled with produced waters prior to discharge or injection. Because of this practice, EPA investigated an option requiring capture of the ''first flush'', or most contaminated portion of, deck drainage. Depending on whether the deck drainage is generated from drilling or production (actual hydrocarbon extraction) operations, this first flush would be subject to the same limitations as would be imposed on either produced water or drilling fluids and cuttings based on the assumption that these two wastestreams could be commingled. Thus, for deck drainage during production, EPA considered as an option zero discharge for the first flush everywhere except in Cook Inlet, where oil and grease limitations would apply. Zero discharge would be required for the first flush captured at drilling operations everywhere. After capturing the first flush, BPT limitations would apply to any remaining deck drainage at either production or drilling operations. Capture of all of deck drainage to meet zero discharge requirements would be impractical due to relatively heavy precipitation that occurs in the Gulf areas.

EPA considered employing a 500 barrel tank to capture the first flush. A tank of this size would be installed at production facilities, and would provide enough storage capacity to capture most, if not all, of the rainfall generated during a 3.5 inch rainfall event at an average size facility. Tanks smaller than 500 bbls would not be large enough to effectively capture the first flush of contaminated drainage. Tanks larger than this would be too costly to install. A 3.5 inch, 24 hour rainfall event would generally only be exceeded once per year in southern Louisiana (the coastal area receiving the most rainfall), and at most, two to three times. After collection, the 500 barrels (or less depending on the size storm event) of deck drainage would be directed through the produced water treatment and would be subject to the same limitations as required for produced water.

For drilling operations, the first 500 barrels would be subject to zero discharge. The basis for this requirement would be that the deck drainage would be directed to on-site drilling waste collection vessels or levees where they would be sent off-site for commercial disposal.

After collection and treatment of the first 500 bbls of deck drainage, any remaining discharge would be subject to the BPT limitations on free oil as measured by the visual sheen test.

The first flush option for deck drainage is estimated to eliminate discharge of more than 9 million bpy of deck drainage (about 78 percent of the total currently discharged) resulting in the removal 82,000 pounds per year of oil and grease.

5. BCT Option Selection

EPA conducted the BCT cost test (described previously in Section VI) for the two deck drainage options. The first flush option did not pass the POTW cost test. The result of this test analysis ranged from $2.13 to $3.45 per pound, and to pass the test, this value must be less than $0.534 per pound.

Thus, EPA has selected BPT, or a limitation prohibiting the discharge of free oil as the BCT limit, for deck drainage. This is a no-cost option because it reflects current practice. It is cost reasonable under the BCT cost test because the POTW test result and the industry cost-effectiveness test results are both zero (and therefore pass their respective tests).

6. Rationale for Selection BAT, NSPS, PSES and PSNS

a. Cost.

No costs are incurred by compliance with the option to require BPT limits for deck drainage. Costs to comply with the first flush option for operations in the Gulf of Mexico would be approximately $13.5 million per year. This includes the costs for both production and drilling operations to comply with a zero discharge requirement for the first flush followed by BPT for any remaining discharge after that. Costs to comply with this option for the Cook Inlet would be approximately $699,000 per year. This includes the costs of treating the first flush of deck drainage with produced water to meet oil and grease limitations of 29 mg/l 30-day average, and 42 mg/l daily maximum, followed by BPT for any remaining discharge after that. Total costs for this option would be approximately $14.2 million per year.

b. Rationale for Selection of BAT and NSPS.

EPA has selected BPT as its preferred option for BAT and NSPS for deck drainage. Since free oil discharges are already prohibited under BPT, there are no incremental compliance costs, pollutant removals, or non-water quality environmental impacts associated with this control option. Since this preferred option limits free oil equal to existing BPT standards, it is technologically available and economically achievable.

EPA has rejected the first flush option for control of deck drainage for several reasons primarily relating to whether this option is technically available to operators throughout the coastal subcategory. Deck drainage is currently captured by drains and flows via gravity to separation tanks below the deck floor. However, the problems associated with capture and treatment beyond gravity feed, power independent systems, are compounded by the possibilities of back-to-back storms which, may cause first flush overflows from an already full 500 bbl tank. In addition, tanks the size of 500 barrels are too large to be placed under deck floors. Installation of a 500 bbl tank would require construction of additional platform space, and the installation of large pumps capable of pumping sudden and sometimes large flows from a drainage collection system up into the tank. The additional deck space would add significantly, especially for water-based facilities, to the cost of this option. Further, many coastal facilities are unmanned and have no power source available to them. Deck drainage can be channelled and treated without power under the BPT limitations.

Capturing deck drainage at drilling operations poses additional technical difficulties. Drilling operations on land may involve an area of approximately 350 square feet. A ring levee is typically excavated around the entire perimeter of a drilling operation to contain contaminated runoff. This ring levee may have a volume of 6,000 bbls, sufficient to contain 500 bbls of the first flush. However, collection of these 500 bbls when 6,000 bbls may be present in the ring levee would not effectively capture the first flush. Costs to install a separate collection system including pumps and tanks, would add significantly to the cost of this option.

While costs are significant, the technological difficulties involved with adequately capturing deck drainage at coastal facilities is the principal reason why this option was not selected. EPA has selected the option requiring no discharge of free oil for BAT and NSPS control of deck drainage. EPA has determined that these limitations and standards properly reflect BAT and NSPS levels of control. EPA did not identify any other available technology for this waste stream. EPA solicits comments on the existence and practicality of treatment systems other than BPT.

EPA's proposed option does not include best management practices (BMPs) for this wastestream as part of these guidelines. EPA currently believes that current industry practices, in conjunction with the requirements as proposed in the proposed general stormwater rule (58 FR 61262-61268, November 19, 1993), would be sufficient to minimize the introduction of contaminants to this wastestream to the extent possible. These stormwater requirements, if promulgated as proposed, would require an oil and gas operator to develop and implement a site-specific storm water pollution prevention plan consisting of a set of BMP's depending on specific sources of pollutants at each site. As noted in the stormwater proposal, the two types of BMP's most effective in reducing storm water contamination are to minimize exposure (e.g., covering, curbing, or diking) and treatment type BMP's which are used to reduce or remove pollutants in storm water discharges (e.g., oil/water separators, sediment basins, or detention ponds).

EPA solicits comment as to whether BMPs should be required for deck drainage as part of the Coastal Guidelines. Such BMPs may include (1) segregation of deck drainage from oil leaks from pump bearings and seals by using drip pans and other collection devices, (2) segregation of contaminated process area deck drainage and runoff from relatively uncontaminated runoff from areas such as living quarters, and walkways, (3) installation of roofs and sheds to divert uncontaminated rainfall from areas with a high potential for generating contaminated runoff, (4) careful handling of drilling fluid materials and treatment chemicals to prevent spills, (5) use of local containment devises such as liners, dikes and drip pans where chemicals are being unpackaged and where wastes are being stored and transferred.

7. PSES and PSNS

EPA is proposing to limit PSES and PSNS for deck drainage as zero discharge. EPA believes that zero discharge for PSES and PSNS is preferable to establishing a limit equal to BPT because generally slugs of deck drainage would interfere with biological treatment processes at POTW's. This is discussed further in the Coastal Technical Development Document. In addition, EPA did not have sufficient data to conduct a pass through analysis of the pollutants found in deck drainage for the reasons discussed further in the Coastal Technical Development Document. EPA solicits comments and data on this issue. Moreover, technical difficulties associated with capture of deck drainage that make it difficult to require limitations other than the BPT, no free oil limit makes it unlikely that this wastestream would be sent to POTW's. EPA solicits comment on whether it would be possible for collection of deck drainage and transmission to a POTW to occur.

E. Treatment, Workover, and Completion Fluids

1. Waste Characterization

Well treatment, workover, and completion fluids are primarily generated during production. Well treatment and workover fluids are inserted downhole in a producing well to increase a well's productivity or to allow safe maintenance of the well. Completion fluids are also inserted downhole after a well has been drilled, and serve to clean the wellbore, and maintain pressure prior to production. In most operations, these fluids resurface once production is initiated and can either be reused, or must be disposed of.

According to results obtained in the 1993 Coastal Oil and Gas Questionnaire, EPA estimates that approximately 275,000 bbls (205,000 and 70,000 bpy of treatment/workover and completion fluids respectively) or these fluids are discharged annually from coastal oil and gas operations in Texas and Louisiana. This amounts to an average of 587 bbls of treatment and workover fluids discharged per year, per well, from approximately 350 wells. For completion fluids, this amounts to an average of 209 bbls discharged per year per well from 334 wells. The 1993 Questionnaire also provides information showing that treatment, workover and completion fluids discharged are commingled with the produced water in Texas and Louisiana prior to injection or discharge. Florida, Alabama and North Slope coastal oil and gas operators do not discharge these fluids.

Based on the 1993 Coastal Oil and Gas Questionnaire and EPA's Region X Discharge Monitoring Reports (described in Section V) all Cook Inlet operators commingle these fluids with produced water for treatment prior to discharge.

The composition of the discharges is highly dependent on the fluid's purpose, but they generally consist of acids (in the case of treatment) or weighted brines (for workover of completion). The principal pollutant in these fluids is oil and grease ranging in concentration from 15–722mg/l. Total suspended solids, another major constituent in these fluids, is present in concentrations ranging from 65 to 1600 mg/l. Prominent priority metals that exist in these wastes include chromium, copper, lead, and zinc. Priority organics are also present including acetone, benzene, ethylbenzene, xylene, toluene, and naphthalene.

EPA estimates that, approximately 22,000 pounds of oil and grease, 50,000 pounds of TSS, 292 pounds of toxic metals, and 417 lbs of toxic organics are being discharged annually in the Gulf of Mexico. In addition, approximately 3.4 million pounds of nonconventionals are being discharged including boron, calcium, cobalt, iron, manganese, molybdenum, tin, vanadium, and yttrium.

2. Selection of Pollutant Parameters

Where zero discharge would be required, EPA would be regulating all conventional, toxic, and non-conventional pollutants found in well treatment, completion and workover fluids.

In Cook Inlet, where discharge would be allowed under Option 2, the parameter ''oil and grease'' would be regulated as an indicator for toxic pollutants. EPA has data indicating that the control of oil and grease will control certain toxic pollutants (including phenol, naphthalene, ethylbenzene, toluene and zinc) as discussed in the Offshore Technical Development Document. As presented in Section VI of the Offshore Technical Development Document when discussing the prohibitions on the discharge of free oil, removal of oil from the discharge effectively removes certain toxic pollutants. Free oil is considered to be ''indicator'' for the control of specific toxic pollutants present in complex hydrocarbon mixtures. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol.

Under EPA's proposed BCT limits, applicable to conventional pollutants, EPA would prohibit the discharge of ''free oil,'' as determined by the static sheen test. EPA would prohibit discharge of ''free oil'' as a surrogate for control over the conventional pollutant ''oil and grease'' in recognition of the complex nature of the oils present in drilling fluids, including crude oil from the formation being drilled.

As will also be discussed below, EPA has determined that it is not feasible to regulate separately each of the constituents in these fluids because these fluids in most instances become part of the produced water wastestream and take on the same characteristics as produced water. Due to the variation of types of fluids used, the volumes and their correspondingly variable constituent concentrations, EPA believes it is impractical to measure and control each individual parameter.

While the oil and grease and, in certain instances, the no free oil limitations limit the discharges of toxic and conventional pollutants found in well treatment, completion and workover fluids, certain other pollutants are not controlled. EPA proposes to exercise its discretion not to regulate these pollutants because EPA has not detected them in more than a very few of the samples within the subcategory and the pollutants when found are present in trace amounts not likely to cause toxic effects. This is consistent with EPA's findings in the Offshore Guidelines. (See EPA's data base for these fluids in the Coastal Technical Development Document).

3. Control and Treatment Technologies

Current practice in the control of discharges from these fluids is to meet the BPT limitations of no free oil (using the visual sheen test). EPA's final general permit applicable to the discharges from coastal oil and gas drilling operations in Texas and Louisiana further prohibits discharges of treatment, workover and completion fluids to freshwater areas. Methods for treatment and discharge, reuse or disposal include:

* Treatment and disposal along with the produced water
* Neutralization for pH control and discharge to surface waters
* Reuse
* Onshore disposal and/or treatment and discharge in coastal or offshore areas.

4. Options Considered

EPA has considered two options for the treatment of treatment, workover, and completion fluids. These are (1) Prohibit the discharges of free oil (equal to the BPT limits) and prohibit the discharges of these fluids to freshwaters of Texas and Louisiana, (2) Limit the discharges equal to EPA's preferred options for produced waters. For produced water BAT limits, EPA is proposing zero discharge everywhere except Cook Inlet, where the proposed produced water control option is to meet limitations on oil and grease of 42 mg/l daily maximum and 29 mg/l 30-day average. For NSPS, PSES, and PSNS, EPA is proposing zero discharge everywhere for produced water.

There are no additional costs to comply with Option 1 because it reflects the current requirements imposed on the industry.

Option 2 would require for BAT, that zero discharge be met for treatment, completion, and workover fluids for all areas except the Cook Inlet, where operators are currently commingling these wastes with produced water, and would be required to meet oil and grease limitations of 29 mg/l 30-day average and 42 mg/l daily maximum. This would annually remove 72,000 pounds of conventionals, 709 pounds of priority toxic pollutants and an additional 3.4 million pounds of nonconventional pollutants. For NSPS, EPA would require zero discharge everywhere, including Cook Inlet. This would remove annually 9,400 pounds of conventionals, 92 pounds of priority toxic pollutants and an additional 440,000 pounds of nonconventional pollutants. EPA is not applying a separate cost in Cook Inlet to comply with this option because these costs are already included in the costs of complying with the produced water option for Cook Inlet (oil and grease limits of 29 mg/l 30-day average/42 mg/l daily maximum).

However, for the Gulf, costs attributed to this option would be operating and maintenance costs associated with commingling with produced water and on-site injection, or hauling off-site to a commercial disposal facility if commingling is not possible. In costing this option for the Gulf, EPA estimated that 77 percent of treatment, workover and completion fluids currently being discharged would be commingled with produced water. This estimate comes from information indicating that 77 percent of produced water discharges are flows greater than 110 bpd (See Section VI) and would be disposed of by onsite injection because flows greater than 110 bpd will be large enough to accommodate the introduction of treatment, workover and completion fluids without fouling the produced water treatment system. The other 23 percent are less than 110 bpd and therefore it would be more cost effective to send the produced waters off-site for disposal rather than install an injection well. (See the Coastal Technical Development Document, Section XII).

Based on these estimates, EPA calculated the costs of compliance with Option 2. These costs included operating and maintenance costs on a dollar per bbl basis for on-site commingling and injection with produced water, and costs of transportation and disposal for commercial disposal. The BAT limits would cost approximately $610,000 annually in the Gulf.

Costs for NSPS requiring zero discharge for treatment, workover and completion fluids were calculated based on EPA's estimate that 187 new wells will be drilled per year in the Gulf Coast (this estimate was obtained from the 1993 Coastal Oil and Gas Questionnaire results). Of these 187, EPA estimated that 76 percent (142 facilities) would be located in Louisiana freshwaters and would not discharge due to state water quality standards (this estimate is also based on the Questionnaire results). The remaining 45 facilities would each generate approximately 800 bbls of treatment, workover and completion fluids per year. Costs to meet zero discharge, based on commingling these fluids with produced water or directing them separately to commercial disposal facilities, are estimated to be approximately $520,000 per year over the next 15 years. These costs are only for the Gulf coast operations. No new sources are expected to be installed in Cook Inlet.

5. Rationale for Selection of Proposed Regulations

a. BCT, BAT, and NSPS.

EPA is proposing to establish BCT limitations equal to BPT, prohibiting the discharge of free oil in well treatment, workover, and completion fluids. Compliance with this limitation would be determined by the static sheen test. Since BPT reflects current practice, this proposed BCT limitation is cost reasonable under the BCT cost test. Based on the available data regarding the levels of conventional pollutants present in these wastes, EPA did not identify any other options which would pass the BCT cost test other than establishing BCT equal to the existing BPT limits. Additional information regarding the results of the BCT cost test for these wastes is presented in the Coastal Technical Development Document. There are no costs or non-water quality environmental impacts associated with this proposed BCT limitation and, since it is equal to BPT, it is technologically available and economically achievable.

EPA is co-proposing both options considered for well treatment, workover, and completion fluids for BAT and NSPS. EPA has determined that both options are technologically and economically achievable and have acceptable non-water quality impacts.

However, due to the high cost effectiveness results for Option 2 (requiring the same limitations as proposed for produced water) a preferred option has not been selected. EPA solicits comment on the appropriateness of either option. Option 1, which would prohibit the discharge of free oil and prohibit the discharge of treatment, workover and completion of fluids to freshwaters of Texas and Louisiana, reflects current regulatory requirements and thus will incur no additional compliance costs, economic or non-water quality environmental impacts. This option would result in no incremental removal of pollutants from this wastestream beyond the existing BPT requirements.

Option 2 would require for BAT zero discharge of treatment, completion, and workover fluids except for Cook Inlet, where EPA would establish oil and grease limitations of 29 mg/l 30-day average, 42 mg/l daily maximum. For NSPS, this option would require zero discharge of all treatment, completion, and workover fluids from all new sources.

Zero discharge is being achieved by many operators (except those in Texas, saline waters of Louisiana, and Cook Inlet) for the treatment, workover, and completion fluids wastestream. The technology basis for zero discharge is commingling this wastestream with produced water or sending it separately to off-site commercial disposal facilities. For Cook Inlet, this option, which also contains allowable discharge limitations is based on commingling with produced water, because commingling of these wastestreams is currently occurring in this area. The specific oil and grease limits proposed are technologically available for the same reasons they are available for control of produced water, as discussed above.

The zero discharge limitation would eliminate all discharges of toxic, conventional, and nonconventional pollutants. The oil and grease limits would be technologically based on improved gas flotation performance (See Section VI.B. of this preamble) and serve to limit the discharge of toxic and conventional pollutants to surface waters.

Zero discharge for treatment, workover and completion fluids in Cook Inlet was not selected for this BAT option because these fluids are commingled with produced water as an integral part of their operations, and because zero discharge for produced water was determined to be uneconomical for Cook Inlet operators.

The costs to meet Option 2 for BAT ($610,000) are relatively minimal since this amount is negligible in comparison to total annual production revenue from Gulf coastal operations.

Costs to achieve zero discharge everywhere for Option 2 NSPS are expected to be negligible. Out of the 187 new wells that will be drilled in the Gulf Coast, 76 percent will not discharge these fluids in freshwaters because of water quality standards requirements. The remaining 45 facilities will each generate approximately 800 bbls of treatment, workover and completion fluids per year (estimates of volumes from the 1993 Coastal Oil and Gas Questionnaire). While some of these fluids may be directed for treatment and disposal to existing production facilities, EPA is conservatively estimating costs of the Option 2 NSPS assuming all of these fluids would be directed to new production facilities for treatment and disposal (or be treated on-site at the new source). For the Gulf, the NSPS requirements under this Option 2 would be the same as those for BAT, thus costs would either be equal to BAT, or less than BAT since new sources can more efficiently design their facilities to comply with zero discharge. Costs for new sources in the Gulf generating treatment, workover and completion fluids to meet zero discharge would be approximately $520,000 per year which is negligible in relation to annual production revenue from Gulf coastal operators.

For Cook Inlet, costs to meet Option 2 requirements for treatment, workover and completion fluids are included in the cost analysis for produced water because current practice there is commingling of these wastestreams (See Section VI.E.). While EPA does not anticipate any new sources to be constructed in Cook Inlet, and therefore has not attributed any costs to NSPS, the NSPS would not cause a significant barrier to entry. These impacts are only a small incremental increase over the impacts resulting from the controls on produced water and drilling fluids and cuttings. Finally the non-water quality environmental impacts of this Option 2 are believed to be acceptable, because like their volumes, they are relatively small (See Section VIII of this preamble) as discussed below.

Option 2 would result in the removal of 3.9 million pounds of conventional, toxic and non-conventional pollutants annually (a total of 2140 in toxic pound equivalents). However the amount of toxic priority pollutants removed is approximately 0.02 percent of this total. The annual compliance costs of $1.1 million (for BAT and NSPS combined) to remove 800 pounds of priority toxic pollutants indicates that this option is not cost effective. (See also EPA's cost effectiveness analyses entitled Cost Effectiveness Analysis of Effluent Limitations Guidelines and Standards for the Coastal Oil and Gas Industry found in the rulemaking record for this proposal).

EPA is soliciting comments on whether the volumes of treatment, workover and completion fluids removed by these options are deminimus, and on the applicability, achievability and practicality of both Options 1 and 2.

b. PSES and PSNS.

Pretreatment standards for treatment workover and completion fluids are being proposed equal to zero discharge. This is because their chemical composition, like produced water, tends to be high in total dissolved solids which may interfere with POTW operations. EPA did not have sufficient data, however, to conduct a pass-through analysis for the pollutants contained in this wastestream. Both interference and pass-through are discussed further in the Coastal Technical Development Document. EPA solicits comments on these issues. Zero discharge for NSPS would not pose barrier to entry for the same reason as discussed under NSPS for this wastestream.

EPA solicits comments on both the occurrence of treatment, workover and completion fluid discharges into POTW's and the appropriateness of pretreatment standards requiring zero discharge for this wastestream.

F. Domestic Wastes

Domestic wastes result from laundries, galleys, showers, etc. Detergents are often part of this wastestream. Waste flows may vary from zero for intermittently manned facilities to several thousand gallons per day for large facilities.

The conventional pollutant of concern in domestic waste is floating solids. The BPT limitations for deck drainage are no discharge of floating solids. To comply with this limit, domestic waste is ground up so as not to cause floating solids on discharge. EPA is proposing to limit floating solids as well for BCT and NSPS. In addition, EPA is proposing to prohibit discharges of foam for BAT and NSPS. Foam is a nonconventional pollutant and its limitation is intended to control discharges that include detergents.

EPA is also proposing to limit discharges of garbage as included in U.S. Coast Guard regulations at 33 CFR Part 151. These Coast Guard regulations implement Annex V of the Convention to Prevent Pollution from Ships (MARPOL) and the Act to Prevent Pollution from Ships, 33, U.S.C. 1901 et seq. (The definition of ''garbage'' is included in 33 CFR 151.05).

The pollutant limitations described above for domestic wastes are all technologically available and economically achievable and reflect the BCT, BAT and NSPS levels of control. Under the Coast Guard regulations, discharges of garbage, including plastics, from vessels and fixed and floating platforms engaged in the exploration, exploitation and associated offshore processing of seabed mineral resources are prohibited with one exception. Victual waste (not including plastics) may be discharged from fixed or floating platforms located beyond 12 nautical miles from nearest land, if such waste is passed through a screen with openings no greater than 25 millimeters (approximately one inch) in diameter. Because vessels and fixed and floating platforms must comply with these limits, EPA believes that all coastal facilities are able to comply with this limit. While not all coastal facilities are located on platforms, compliance with a no garbage standard should be as achievable, if not more so for shallow water or land based facilities that have access to garbage collection services. Further, the final drilling permit promulgated by Region VI for coastal Texas and Louisiana incorporates these Coast Guard regulations.

Since these BCT, BAT and NSPS limitations for domestic waste are already in either existing NPDES permits or Coast Guard regulations, these limitations will not result in any additional compliance cost, and thus these limits are economically achievable. Also, these limits and standards will have no additional non-water quality environmental impacts. There are no incremental costs associated with the BCT limitations; therefore, it is considered to pass the two part BCT cost reasonableness test.

No discharge of visible foam is required by Region X's NPDES permit for Cook Inlet drilling. No discharge of floating solids is included in the Region X's BPT Cook Inlet general permit, the Region X's drilling permit and Region IV's general permit for coastal operators.

Pretreatment standards are not being developed for domestic wastes because they are compatible with POTWs.

G. Sanitary Wastes

Sanitary wastes from coastal oil and gas facilities are comprised of human body wastes from toilets and urinals. The volume of these wastes vary widely with time, occupancy, and site characteristics. A larger facility, such as an offshore platform, typically discharges about 35 gallons of sanitary waste daily. Sanitary discharges from coastal facilities would be expected to be less than this value since the manning levels at most coastal facilities is less than that at offshore locations.

Existing BPT limitations for facilities continuously manned by 10 or more people requires sanitary effluent to have a minimum residual chlorine content of 1 mg/l, with the chlorine concentration to remain as close to this level as possible. Facilities intermittently manned or continuously manned by fewer than 10 people must comply with a BPT prohibition on the discharge of floating solids. EPA's Regions VI and IV NPDES general permits for coastal facilities also impose limits on the discharge of TSS, fecal coliform count, BOD and floating solids. EPA's Region X general NPDES permit for Cook Inlet also requires limitations for these same parameters in addition to requirements for foam and free oil.

EPA considered zero discharge of sanitary wastes based on off-site disposal to municipal treatment facilities or injection with other oil and gas wastes. Off-site disposal would require pump out operations, that while available to certain land facilities, are not available to remote or water-based operations. Because sanitary wastes are not exclusively associated with oil and gas operations, which are routinely injected in Class II wells, zero discharge based on Class II injection was not considered for sanitary wastes. EPA solicits comments on the selected option for sanitary wastes regarding the pollutant regulated, the limitation itself, and other possible disposal options, including marine sanitation devices that are designed to prevent discharge (Type III, 33 CFR 159.3(s)).

EPA is proposing to limit sanitary waste discharges for BCT and NSPS equal to BPT limitations. Sanitary waste effluents from facilities continuously manned by ten (10) or more persons must contain a minimum residual chlorine content of 1 mg/l, with the chlorine level maintained as close to this concentration as possible. Coastal facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons must comply with a prohibition on the discharge of floating solids.

Since there are no increased control requirements beyond those already required by BPT effluent guidelines, there are no incremental compliance costs or non-water quality environmental impacts associated with BCT and NSPS limitations for sanitary wastes. Since these limitations are equal to BPT, they are available and economically achievable. In addition, the BCT limitation is also considered to be cost reasonable under the BCT cost test. Since the POTW test result and the industry cost-effectiveness test results are both zero (and therefore pass their respective tests), the limitation is cost reasonable.

EPA is not establishing BAT effluent limitations for the sanitary waste stream because no toxic or nonconventional pollutants of concern have been identified in these wastes.

Pretreatment standards are not being developed for sanitary wastes because they are compatible with POTWs.

VII. Economic Analysis

A. Introduction

EPA's economic impact assessment is presented in the Economic Impact Analysis of Proposed Effluent Limitations and Guidelines, and Standards for the Coastal Oil and Gas Industry (hereinafter, ''EIA''). This report details the investment and annualized costs of compliance with the rule for the industry as a whole and the impacts of the compliance costs on affected wells, platforms, and operators in the coastal oil and gas industry, both existing and future. The report also estimates the economic effect of compliance costs on Federal and State revenues, balance of trade considerations, and inflation.

EPA also has conducted an analysis of the cost-effectiveness of alternative treatment options. The results of the cost-effectiveness analysis are expressed in terms of the incremental costs per pound-equivalent removed. Pound-equivalents account for the differences in toxicity among the pollutants removed. Total pound-equivalents are derived by taking the number of pounds of a pollutant removed and multiplying this number by a toxic weighting factor. The toxic weighting factor is derived using ambient water quality criteria and toxicity values. The toxic weighting factors are then standardized by relating them to a particular pollutant, in this case copper.

Cost-effectiveness is calculated as the ratio of incremental annualized costs of an option to the incremental pound-equivalents removed by that option. This analysis, Cost-Effectiveness Analysis of Effluent Limitations Guidelines and Standards for the Coastal Oil and Gas Industry (hereinafter, the ''CE Report''), is included in the record of this rulemaking. Since the discharges are primarily to a marine or brackish environment, salt-water toxic weighting factors (which typically are lower than freshwater toxic weighting factors, thus they generate lower pound-equivalents overall) were used wherever they were available.

Cost-effectiveness is a measure of costs and relative economic efficiency of the technology options being considered to remove toxic pollutants. EPA includes direct compliance costs, such as capital expenditures, operations and maintenance costs and in some cases monitoring costs (*i.e.*, direct compliance costs), when estimating cost-effectiveness. EPA has not included in previous effluent guidelines and standards costs associated with the economic impact of the technology options in the costs used in the cost-effectiveness analysis. Consistent with this, for this effluent guidelines, EPA has included capital expenditures and operation and maintenance, but not the cost of the lost oil/gas production in its analysis of the incremental cost-effectiveness of different technology options. EPA does consider the lost production as an economic impact on this industry, and has included lost production in its economic impact analysis. During the interagency review a question was raised whether EPA should treat the lost oil/gas production as a compliance cost to the facility. EPA solicits comments on: (1) Whether the possibly permanent loss in oil/gas production associated with premature closing of these wells may be different from lower production of manufacturing goods that occurs in any production period as a result of higher production costs, and (2) whether or not the lost production of oil/gas should be considered when determining the cost-effectiveness on the technology options for this industry.

B. Economic Methodology

The EIA provides the results of a number of measures of economic impact resulting from the proposed Coastal Guidelines. These measures include production losses (measured in terms of total lifetime production lost, losses in net present value (NPV)[2] of production, and years of production lost), impacts on federal and state revenues; impacts on firms; impacts on employment; impacts on inflation and balance of trade; impacts on small businesses; and impacts on new sources in terms of barriers to entry. All impacts measured in this EIA do not take into account the requirements of the EPA Region VI General Permits for the Coastal Oil and Gas Industry covering disposal of produced water.

These impacts are also based on the assumption that oil prices will remain, in real terms, approximately $18 per barrel over the timeframe of the analysis. This assumption is substantiated, at least for this decade, by recent industry forecasts. Note that if the price of oil changes significantly, impacts could also change.

1. Gulf of Mexico

EPA used the 1993 Coastal Oil and Gas Questionnaire authorized under section 308 of the CWA to obtain the information necessary to model impacts at wells determined to be currently discharging and which were determined to be continuing to discharge at least through the third quarter of 1996. Incremental compliance costs specific to these wells or the produced water separation and treatment facilities associated with these wells (prorated on a cost per barrel basis to make them well-specific) were used to derive the incremental costs to the affected wells. By Gulf of Mexico, the EIA does not generally include Gulf coastal facilities in Alabama and Florida, since coastal operators in these states are already required to meet zero discharge, and thus, these facilities would not incur additional costs from this rule.

A financial model showing cash flow over a maximum 30-year time frame (or less if a well's flow becomes negative before 30 years) was developed and adapted to each well using well-specific data in the Questionnaire. Costs included in the models include those associated with current production costs and revenues, which were extrapolated over the lifetime of the project to establish baseline lifetime production. Other baseline summary statistics included years of economic lifetime, corporate cost per barrel of oil equivalent (BOE), and net present value of lifetime production. Then, capital and annual operating and maintenance (O&M) costs associated with various regulatory options were added to the baseline costs. The model recalculates the economic lifetime of the wells, annualizes the regulatory costs over the new project lifetime, and recalculates production and financial summary statistics. Well impacts were evaluated by determining the change from the baseline values caused by the increased regulatory costs. Production losses are measured as reductions in hydrocarbon extraction resulting from immediate closure of existing wells and curtailed lifetimes. These were based on the decrease in production and decrease in net present values for the wells induced by the regulatory costs. That is, if a well became unprofitable with the additional costs, it was assumed to shut in, either in the first year or earlier than it might have under baseline assumptions.

To provide more accuracy in estimating the total annual costs to the Gulf of Mexico (GOM) coastal oil and gas industry, these costs were derived using state permit data on discharging facilities and compliance cost estimates developed on a per-facility basis. Thus costs were not based on extrapolations from survey data. These costs are pre-tax (although the financial models account for impacts based on the appropriate post-tax costs). EPA re-emphasizes that this analysis assumes that the Region VI permit for produced water is not part of the baseline scenario.

EPA also analyzed secondary impacts of the regulation. These include: revenue losses to the federal government due to tax shields on expenditures and loss of taxable revenues, revenue losses to State governments through lower severance tax payments and royalties, changes in the balance of trade and inflation, employment losses (both primary and secondary) based on production losses and firm failures, and employment gains (involved with manufacturing, installing, and operating pollution control equipment). Impacts on new sources also are investigated and a regulatory flexibility analysis is performed.

2. Cook Inlet

The same type of financial model used in the Gulf of Mexico portion of the analysis was adapted to model 14 platforms (one currently shut in but with potential for future production) in the Cook Inlet. The same types of impacts from a variety of regulatory options for this region also were estimated. One difference between the Cook Inlet model and the Gulf model is that the Cook Inlet model operates at the platform level instead of the well level. Impacts are evaluated for platforms, whose production rates change with the addition of new and recompleted wells.

C. Summary of Costs and Economic Impacts

1. Overview of Economic Analysis

The economic analysis has five major components: (1) An estimate of the number of existing wells (Gulf of Mexico) and platforms (Cook Inlet) and projected wells/platforms that incur costs under this rule; (2) an estimate of the annual aggregate (pre-tax) cost of complying with the regulation using capital and O&M costs per Cook Inlet platform or Gulf of Mexico treatment facility as estimated in the Development Document; (3) use of an economic model to evaluate per-well/platform impacts on production and economic life; (4) an evaluation of impacts on firms, future oil and gas production, Federal and State revenues, balance of trade, employment and other secondary effects; and (5) the performance of a regulatory flexibility analysis as required under the Regulatory Flexibility Act to determine whether impacts on small firms are disproportionate to those on large firms.

[2] Net present value is the total stream of production revenues minus costs over a period of years discounted back to present value, under the assumption that a future dollar is worth less than a dollar now.

The base year for the economic analysis is 1992, so all costs are reported in 1992 dollars. This is the year for which data were gathered in the 1993 Coastal Oil and Gas Questionnaire and was the most recent year for which a complete set of cost, revenue, and production data were available. Any costs not originally in 1992 dollars were inflated or deflated using the Engineering News Record Construction Cost Index, unless otherwise noted in the EIA (see EIA for details).

The industry profile used in this analysis is presented in Section IV. EPA estimates that there are 4,675 existing wells in the Gulf of Mexico Coastal Region, of which 1,588 are estimated to still be discharging produced water in 1996, according to estimates based on Questionnaire 308 survey results. By Gulf of Mexico, EPA has not included Alabama or Florida since these facilities are currently meeting zero discharge. As noted above, this costing approach is conservative because independent of this rule, an additional 28 production facilities (with an estimated 213 wells) in coastal Louisiana will be required by Louisiana state water quality standards to achieve zero discharge by January 1997. Six new production facilities are expected to be built each year in the Gulf region. The costs for these new projects are assigned as NSPS compliance costs. In Cook Inlet, no new facilities are anticipated, thus no NSPS costs are calculated for purposes of estimating the total costs of the rule. EPA has, however, analyzed whether the NSPS requirements for Cook Inlet would create a barrier to entry for any new sources that might begin to operate in Cook Inlet.

EPA examined the effect of BPT, BCT, BAT, and NSPS regulatory options. BPT options have no costs or impacts and are discussed no further here. BCT options were examined using BCT cost tests (see Section VI). BAT and NSPS economic impacts are discussed in this section. The following wastestreams are regulated by this rule: produced water; drilling wastes; well treatment, workover, and completion fluids; produced sand; deck drainage; sanitary wastes; and domestic wastes. For sanitary and domestic wastes, the BAT and NSPS options proposed are current permit conditions, thus no costs or impacts are incurred as a result of BAT or NSPS requirements for these wastestreams. For deck drainage, the limits are based on BPT, thus costs and impacts of BAT or NSPS requirements are zero. For produced sand, current practice is zero discharge, and zero discharge is the only option considered for BPT, BAT or NSPS. Thus, no costs or impacts are expected to result from BAT or NSPS requirements for produced sand. Therefore, the remainder of this section discusses the costs and impacts of BAT and NSPS options only for produced water; drilling waste; and treatment, workover, and completion fluids.

In all, there are 10 BAT regulatory options: 5 for produced water, 3 for drilling wastes, and 2 for treatment, workover, and completion fluids. These options are described in Section VI. The economic impacts from these options are assessed individually in this Section. Selected NSPS options are also discussed in these sections.

2. Total Costs and Impacts of the Regulations

This section presents the costs and impacts of the selected BAT and NSPS regulatory options. The total annual costs of the BAT and NSPS regulatory alternatives are presented in Table 6. Note that the costs and impacts of this rule would be substantially reduced if the effects of the recently finalized EPA Region VI General Permit were to be incorporated in this rule. The preferred BAT regulatory option for produced water is Option 4, zero discharge everywhere except in Cook Inlet where discharges are allowed provided oil and grease limitations, based on improved gas flotations, are met.

TABLE 6.—TOTAL COSTS OF BAT AND NSPS OPTIONS (1992$)

<table>
<tr><th rowspan="2">Wastestream[1]</th><th colspan="5">Annual compliance costs ($ million/yr)</th></tr>
<tr><th colspan="3">BAT</th><th colspan="2">NSPS</th></tr>
<tr><td>Produced water</td><td colspan="3">30.86</td><td colspan="2">4.48</td></tr>
<tr><td rowspan="3">Drilling fluids and cuttings</td><td colspan="3">Co-proposal</td><td rowspan="3" colspan="2">[2] 0</td></tr>
<tr><td>Opt 1</td><td>Opt 2</td><td>Opt 3</td></tr>
<tr><td>0</td><td>1.4</td><td>3.89</td></tr>
<tr><td rowspan="3">Treatment, workover, and completion fluids</td><td colspan="3">Co-proposal</td><td colspan="2">Co-proposal</td></tr>
<tr><td>Opt 1</td><td colspan="2">Opt 2</td><td>Opt 1</td><td>Opt 2</td></tr>
<tr><td>0</td><td colspan="2">0.61</td><td>0</td><td>0.52</td></tr>
<tr><td>Total</td><td colspan="3">30.86–35.36</td><td colspan="2">4.48–5.00</td></tr>
</table>

[1] EPA selected no-cost options for all other wastestreams.
[2] No new sources expected in Cook Inlet.

The three options considered for drilling fluids and cuttings BAT and NSPS contain zero discharge for all areas, except two of the BAT options contain allowable discharges for Cook Inlet. One of these options which would allow discharges meeting a more stringent toxicity limitation if selected for the final rule, would require an additional notice for public comment since the specific toxicity limitation has not been determined at this time. The three options are: Option 1—zero discharge for all areas except Cook Inlet where discharge limitations require toxicity of no less than 30,000 ppm (SPP), no discharge of free oil and diesel oil and no more than 1 mg/l mercury and 3 mg/l cadmium in the stock barite, Option 2—zero discharge for all areas except for Cook Inlet where discharge limitations would be the same as Option 1, except toxicity would be set to meet a limitation between 100,000 pm (SPP) and 1 million ppm (SPP), and Option 3—zero discharge for all areas. EPA is co-proposing two options for BAT and NSPS for treatment, workover and completion fluids. Option 1 would require no discharge of free oil and prohibit discharges to freshwaters of Texas and Louisiana. This option reflects current practice. Option 2 would require the same limitations as the preferred option for produced water. This option would require for BAT that, discharges of treatment, workover and completion fluids would be prohibited in all coastal areas except Cook Inlet. In Cook Inlet, these discharges would be required to meet a daily maximum oil and grease limitation of 42 mg/l and a 30 day average of 29 mg/l. Option 2 would require zero discharged of these fluids everywhere for NSPS.

The total cost of compliance with these selected BAT options is $30.9 million to $35.4 million per year in 1992$'s (or $33.5 million to $38.4 million in 1994$'s). Additionally, compliance with the BAT options would result in up to approximately $9.5 million in lost oil and gas revenues, taxes and royalties annually.[3]

NSPS requirements for produced water is zero discharge (only the Gulf is expected to have new sources). The options being co-proposed for NSPS for drilling fluids and cuttings and treatment, workover and completion fluids are the same as those considered for BAT. Total compliance cost of NSPS for this proposal ranges from $4.48 to approximately $5 million annually in 1992 $'s (or $4.9 to $5.4 million annually in 1994 $'s). Additionally, compliance with the selected NSPS options could also result in roughly $1 to 2 million in lost oil and gas revenues, royalties and taxes annually. Costs of NSPS for produced water are associated only with six new source production facilities per year projected in the Gulf region. No new sources are projected in Cook Inlet. For the six new production facilities constructed per year in the Gulf, costs of the produced water NSPS are estimated to be approximately $4.48 million per year or $38.4 million (present value) over a 15-year time frame.

Costs of NSPS for well treatment, workover and completion fluids are based on EPA projections that 45 new source wells would be discharging these fluids (without this rule) in the Gulf region. No new sources are projected in Cook Inlet. For the 45 new source wells in the Gulf region costs of the NSPS options for well treatment, workover and completion fluids are estimated to range from $0.00 to approximately $0.52 million per year or $0.00 to $4.4 million (present value) over a 15-year time frame.

Because current practice for control of drilling fluids and drill cuttings in the Gulf region is zero discharge and no new sources are projected in Cook Inlet, no additional costs will be incurred due to NSPS for drilling fluids and drill cuttings.

Total compliance cost of all BAT and NSPS requirements ranges from $35.34 million to $40.36 million per year in 1992 $'s (or $38.3 million to $43.8 million annually in 1994 $'s). These compliance costs will also result in up to $11.5 million in lost oil and gas revenues, royalties and taxes annually. Note that these costs are a small percentage of coastal revenues and operating costs (the direct costs of operating the business, i.e., not including general and administrative costs, depletion, depreciation, taxes, interest, etc.). Total revenues stemming from coastal operations among coastal firms (Texas, Louisiana, and Cook Inlet, Alaska, only) are estimated to be $6.1 billion per year. Thus the total annual cost of the proposed Coastal Guidelines is estimated to be at most 0.7 percent of annual coastal revenues. The total coastal operating costs among coastal firms is estimated to be $1.2 billion per year, thus annual compliance costs of this proposed rule are estimated to be up to 3.3 percent of total annual operating costs.

BAT production losses under the selected options are expected to total at most 40.2 million barrels of oil equivalent (BOE) over the lifetime of the wells and platforms as a result of the regulatory options (average postcompliance lifetime is 10 years in both the Gulf and Cook Inlet). In Cook Inlet, the production loss over the expected productive lifetime of the platforms is expected to be up to 12.4 million total BOE, which is 3.1 percent of the estimated lifetime production for the region. In the Gulf, the lifetime production loss is expected to be up to 27.9 million total BOE, which is 0.9 percent of a high estimate of lifetime production and 1.7 percent of a low estimate of lifetime production in the Gulf. For the two regions combined, the maximum 40.2 million BOE loss (or 17.9 million BOE in present value) in production is 1.1 percent to 2.0 percent of total lifetime production. These losses are associated with declines in the net present value of producer income totalling up to $144.5 million in the Gulf and $15.9 million in Cook Inlet for a total of $160.4 million or 0.7 to 1.5 percent of total net present value of baseline producer income in the two regions.[4] These losses result from both immediate shut in of wells or platforms and/or shortened economic lifetimes. A total of up to 111 Gulf wells (2.4 percent of all current coastal Gulf wells) and no Cook Inlet platforms are considered likely to shut in at once under the proposed options. These shut-in wells tend to be relatively low-producing or marginal wells as can be seen from the relatively lower percentage of production affected as compared to a higher percentage of wells.

A maximum of 12 firms owning and/or operating Gulf Coastal wells might possibly fail as a result of the proposed regulatory options. Data were not available to rule out the possibility of firm failure, so they were counted as potential firm failures, thus the actual number of firm failures could be as few as none. No failures are predicted for operators in Cook Inlet. It is estimated that the majority (72 percent) of firms in the Gulf Coastal region by 1996 will not discharge produced water. Thus, most firms will incur no compliance costs. The Gulf Coastal firms, therefore, are potentially expected to face average (median) declines in equity or working capital of 0 percent. Discharging firms are potentially expected to face average (median) declines in equity and working capital of 0.37 percent and 2.63 percent, respectively.

The options potentially could result in a present value loss of up to $91 million in federal and state income tax revenues over an average of 10 years, or up to $13.6 million, on average, annually (primarily federal taxes). This loss is only 11 percent of income taxes from discharging wells and platforms alone. Losses to state revenues due to a potential loss of severance taxes total $10.8 million over 10 years, or $1.6 million, on average, annually. This loss is only 3.8 percent of severance taxes from discharging wells and platforms alone. The states could also potentially lose royalties totaling at most, an estimated present value of $39.4 million over 10 years, or $5.9 million, on average, annually, which is only 5.8 percent of royalties collected from discharging wells and platforms alone. These effects are negligible compared to federal and state revenues and royalties collected.

The proposed rule is not expected to affect energy prices, international trade, or inflation, and would have a minimal impact on national-level employment. Primary employment losses would be

[3] The industry will not experience the entire impact of these costs because depreciation allowances and increased costs of production stemming from these compliance costs will serve to reduce taxable income. Thus a portion of these costs will be borne by federal and state governments rather than industry or individual firm owners. This portion is known as industry's "tax shield." This impact to governments is, however, noted in the analyses discussed below.

[4] The losses of $160.4 million included costs of technology and resulting production losses.

expected to be 181 full-time equivalents (FTEs), which is 3.1 percent of total Gulf and Cook Inlet employment (minus baseline employment losses). Primary and secondary losses are expected to total 518 FTEs. Net employment losses (including secondary effects and accounting for employment gains) are expected to be 121 FTEs. Additionally, an estimated 1,561 FTEs would be lost in the Gulf, on average, five years sooner (in 10 years rather than in 15 years) because of declines in wells' productive lifetimes. However, because these impacts are not felt, on average, for 10 years and because ample time is available for industry to adjust to declines in wells' productive lives through natural job attrition, these impacts are not considered major. This loss is equivalent to declines in total Gulf coastal employment averaging 3 percent per year over a 10-year period under the regulation, compared to declines averaging 2 percent a year over a 15-year period without the regulation or at most 337 FTEs on an equivalent first year loss basis. Table 7 summarizes the impacts discussed above. In Cook Inlet, platforms shut in, on average, 1 year earlier (in 10 years instead of 11 years). This impact is considered minor because ample time is still available for workers to find alternative employment.

TABLE 7.—SUMMARY OF ECONOMIC IMPACTS TO GULF OF MEXICO AND COOK INLET REGIONS FROM THE SELECTED BAT OPTIONS

Impact [1]	Option No. 4 produced water	Drilling waste			TWC		Total impacts [2]
		OPT 1	OPT 2	OPT 3	OPT 1	OPT 2	
Number of wells or platforms shut in:							
Wells	111	0	0	0	0	0	111 wells.
Platforms	0	0	0	0	0	0	0 platforms.
Present value of lost production (million BOE).	15.2	0	2.7	5.4	Negl.	Negl.	15.2 to 17.9.
Total production lost (million BOE)	32.4	0	3.6	7.8	Negl.	Negl.	32.4 to 40.2.
Present value of producer income lost ($000)	$153,209	0	$263	$6,089	Negl.	Negl.	$153,209 to $160,409.
Present value of federal taxes lost ($000)	$84,903	0	$2,586	$7,925	Negl.	Negl.	$84,903 to $90,950.
Present value of lost severance taxes ($000)	$10,676	0	$133	$272	Negl.	Negl.	$10,676 to $10,815.
Present value of lost royalties to states	$34,255	0	$4,274	$9,394	Negl.	....	$34,255 to $39,375.
Total present value losses ($000) [3]	$283,043	0	$7,256	$23,680	Negl.	Negl.	$283,043 to $301,549.

[1] Impacts from selected options for other wastestreams are expected to be negligible.
[2] Impacts are not additive. Some double counting or undercounting of impacts occurs in the Cook Inlet analysis if produced water impacts are added to drilling waste impacts. The total reflects the removal of double counting, with corrections made for undercounting.
[3] Includes only dollar figures in columns. Losses comprise both compliance costs and value of lost production (net operating costs). Note that these losses are not annual losses.

Based on the impacts predicted, EPA finds the costs of the proposed BAT limitations to be economically achievable for the Coastal Oil and Gas Industry.

NSPS requirements for produced water in the Gulf (Cook Inlet NSPS impacts are discussed below), for drilling wastes, and for miscellaneous wastes are equivalent to BAT requirements. Costs for designing in compliance equipment are typically less than those for retrofitting the same compliance equipment to existing operations. Since new sources would most likely face costs of compliance equal to or less than existing operations, NSPS for Cook Inlet produced water are projected to pose no barriers to entry.

NSPS for produced water in Cook Inlet are more stringent than BAT requirements; however, declines in net present value of production for existing platforms under Coastal Guidelines BAT limitations (2.4 percent) are only negligibly less than net present value declines modeled for new sources under a zero discharge scenario (2.9 percent). Further, the modeled NSPS platform shows excellent internal rates of return (a measure of profitability) postcompliance, so NSPS should not play a major role in a decision to undertake the construction, development, and operation of a platform. Thus EPA finds that no significant barriers to entry will be created by NSPS for produced water in Cook Inlet and that these standards should be economically achievable, given the minimal impact on net present value and the internal rate of return.

D. Produced Water

1. BAT

As noted earlier, this analysis of impacts associated with the effluent guidelines for produced water does not consider the effects of the Region VI General Permit for produced water. Because the Region VI General Permit has been promulgated as zero discharge, the costs and impacts of the limits on produced water in the Gulf of Mexico would be substantially less.

Total production losses associated with the proposed option, Option #4 for produced water (zero discharge except for Cook Inlet), are expected to total 32.4 million BOE (or 15.2 million BOE in present value) over the lifetime of the wells and platforms subject to the rule.[5] In Cook Inlet, the production loss is expected to be 4.6 million BOE, which is 1.6 percent of the estimated lifetime production for the region. In the Gulf, the production loss is expected to be 27.9 million BOE. Lifetime production in the Gulf is estimated to be 1,055 to 3,183 million BOE (693 to 13,910 BOE in present value terms) (over a 30-year time frame, based on a low and high estimate of decline rate in the region). Thus, this lost production is 0.9 to 1.7 percent of expected lifetime production in the Gulf. For the two regions combined, the lost production of 32.4 million BOE would result in a loss of 1.0 percent to 1.7 percent of total lifetime production. These losses are associated with declines in the net present value of producer income totalling $144.5 million in the Gulf and $8.8 million in Cook Inlet for a total of $153.3 million (total lifetime losses). These losses result from both immediate shut in of wells or platforms and

[5] Total losses calculated independently for produced water and drilling waste will not add exactly to the number cited above for combined losses because the independent estimates double count a very small portion of lost production in Alaska (about 1.3 percent of production).

shortened economic lifetimes. A total of 111 Gulf wells (2.4 percent of all current coastal Gulf wells) and no Cook Inlet platforms are considered likely to shut in as a result of this rule. These shut-in wells tend to be relatively low-producing and marginal wells.

At most, 12 firms owning and/or operating Gulf Coastal wells (2.8 percent of the estimated 435 Gulf Coastal region operators) might potentially fail as a result of the selected BAT option (i.e., data are not available to rule out this possibility, although the actual number could be as small as none). No firm failures are predicted for operators in Cook Inlet. The ''average'' Gulf Coastal firm does not discharge produced water (there are a total of 435 firms and more than 50 percent—actually 72 percent—will not be discharging in coastal areas by 1996). Thus, Gulf Coastal firms are potentially expected to face average (median) declines in equity or working capital of 0 percent since the majority of Gulf firms do not discharge and thus will not incur compliance costs. Of the 122 discharging firms, average (median) declines in equity or working capital of 0.37 percent or 2.63 percent are expected to occur, respectively.

The selected option potentially could result in a $84.9 million loss in federal tax revenues over an average of 10 years, or $12.6 million, on average, annually. This loss is only 10 percent of income taxes collected from discharging wells and platforms alone. Losses to state revenues due to a potential loss of severance taxes total $10.7 million or $1.6 million, on average, annually. This loss is only 3.8 percent of severance taxes from dischargers alone. State royalties lost total $34.3 million, or $5.1 million, on average, annually. This loss is only 5.1 percent of royalties from dischargers alone. These effects are negligible compared to federal and state revenues and royalties collected.

The selected option is not expected to affect energy prices, international trade, or inflation, and will have a minimal impact on national-level employment. Primary employment losses are expected to be 181 FTEs. Primary and secondary losses are expected to total 518 FTEs. Net employment losses (including secondary effects and employment gains) are expected to be 128 FTEs. Table 8 summarizes the impacts from the proposed produced water option.

Based on the minimal impacts predicted, EPA finds that the proposed BAT option for produced water is economically achievable for the Coastal Oil and Gas Industry.

2. NSPS

This section discusses the barrier-to-entry analysis for all regions but Cook Inlet first, then NSPS relative to Cook Inlet is discussed separately. Total annual costs associated with NSPS requirements for produced water in the Gulf of Mexico (the only region where NSPS projects are of concern) are $4.5 million per year. The selected NSPS requirement is equivalent to BAT requirements in this region. Because NSPS is equivalent to BAT outside of Cook Inlet region, and BAT has been found to be economically achievable, NSPS requirements for all but Cook Inlet (which will be discussed separately below) would not pose a barrier to entry and are considered economically achievable.

TABLE 8.—SUMMARY OF ECONOMIC IMPACTS TO GULF OF MEXICO AND COOK INLET REGIONS FROM PRODUCED WATER BAT OPTION NO. 4

[Zero discharge except Cook Inlet]

Impact	Option No. 4 produced water
Number of wells or platforms shut in.	111 wells. 0 platforms.
Present value of production loss (million BOE).	15.2.
Total production lost (million BOE).	32.4.
Net present value of producer income lost ($000).	$153,209.
Present value of federal taxes lost ($000).	$84,903.
Present value of lost severance taxes.	$10,676.
Present value of lost royalties to states.	$34,255.
Total present value losses ($000).	$283,043.
Employment effects	128 FTEs lost.

Two NSPS economic models were run for Cook Inlet in the EIA for the Offshore Effluent Guidelines (EPA, 1993, Table 7–19; Table 7–21).[6] These models include a 24-slot gas/oil platform and a 12-slot gas platform. The gas/oil platform was estimated to incur incremental compliance costs for produced water disposal under a zero discharge requirement of $1.8 million annually (inflated to 1992 dollars). The key impacts affecting whether a new project would be undertaken (which would lead to conclusions about barriers to entry) include impacts on net present value (NPV) and impacts on the internal rate of return (IRR). The gas/oil 24 is projected to face declines in NPV of 2.9 percent from baseline under a zero discharge requirement for produced water. IRR drops 5.1 percent, however, this drop is estimated to be from 39 percent in the baseline to 37 percent in the zero-discharge scenario. These impacts are not likely to affect the decision to undertake a project in Cook Inlet (given production levels similar to existing Cook Inlet platforms). Additionally, the impact on NPV from the zero-discharge requirement is not substantially different from the impacts on NPV from the proposed BAT option under the Coastal Guidelines at existing Cook Inlet platforms. The decline in NPV projected for the Coastal rule BAT option is 2.4 percent. Thus, existing platforms and new platforms will face similar impacts on NPV even though the NSPS requirement is more environmentally stringent than the BAT requirement.

Costs and impacts associated with the Cook Inlet 12-slot platform are much less than those associated with the 24-slot platform or with existing platforms under the proposed BAT option for produced water under the Coastal Guidelines (see EPA, 1993, Table 7–21 and Section D.1 of this preamble).

Based on the analyses performed for the Offshore Guidelines (which continue to be relevant analyses for the Coastal Guidelines), EPA concludes that impacts on new sources in Cook Inlet are minimal and that NSPS requirements should pose no significant barriers to entry for two reasons: (1) declines in returns (measured as NPV and IRR) most likely would not affect the decision to undertake a new project since operations would still be quite profitable and (2) the level of impacts on new sources from NSPS requirements are not substantially greater than those on existing sources from BAT requirements.

E. Drilling Fluids and Drill Cuttings

1. BAT

As noted above, current practice in the Gulf of Mexico region is zero discharge of drilling fluids and drill cuttings; and therefore, this proposed rule would result in no additional costs to Gulf operators. The three options being co-proposed affect Cook Inlet operations. Option 1 would result in no economic impacts. Option 2 would cause a total 3.6 million BOE loss in production over 15 years. This represents a 1.2 percent reduction in the estimated lifetime production for the

[6] NSPS models were run for Cook Inlet in the Offshore EIA because EPA considered including Cook Inlet in the offshore subcategory, but finally included the operations in the Coastal subcategory. The NSPS models constructed for the Offshore EIA were used as the basis for modeling the existing Cook Inlet platforms in the Coastal Guidelines EIA, thus comparisons between NSPS platforms and BAT platforms can be made.

existing platforms in Cook Inlet as result of three wells not being drilled. The net present value of this production loss (reduction in producers' net income) is $263,000 or less than 0.1 percent of baseline net present value. The average well life decreases by 0.2 years as a result of this option. Additionally, Federal income tax receipts would decline by $2.6 million, state income tax receipts by $133,000 and royalties paid to Alaska by $4.3 million.

Option 3 would cause a production loss of 7.8 million BOE, which is equal to a 2.5 percent decline in the lifetime production in Cook Inlet. No platforms are expected to close. Federal income tax lost (over the life of the platforms) is estimated to decline $7.9 million (3.4 percent of baseline), or $1.3 million, on average, per year. No firm failures are predicted for operators in Cook Inlet. Total state severance tax revenues are predicted to decline by $0.27 million (0.5 percent of baseline), or $0.04 million, on average, annually. Option 3 are not expected to affect energy prices, international trade, or inflation, and would have a minimal impact on national-level employment. Employment losses are not expected. Employment gains (including secondary effects) are expected to be approximately 7 FTEs, under either Option 2 or Option 3.

Based on the impacts predicted, EPA finds that the costs of all three options for drilling wastes are economically achievable for the Coastal Oil and Gas Industry. Table 9 summarizes the impacts from the proposed BAT options for drilling waste.

TABLE 9.—SUMMARY OF TOTAL ECONOMIC IMPACTS FROM DRILLING WASTE OPTION NO. 3

Impact	Option No. 3 drilling waste		
	Opt 1	Opt 2	Opt 3
Number of Wells or platforms shut in:			
Wells	0	0	0.
Platforms	0	0	0.
Present value of total production lost (million BOE)	0	2.7	5.4.
Total production lost (million BOE)	0	3.6	7.8.
Net present value of producer income lost ($000)	0	$263	$6,089.
Present value of federal taxes lost ($000)	0	$2,586	$7,925.
Present value of lost severance taxes ($000)	0	$133	272.
Present value of lost royalties to states	0	$4,274	$9,394.
Total present value losses ($000)	0	$7,256	$23,680.
Employment effects	0	7 FTEs gained	7 FTEs gained.

2. NSPS

The same options are being considered for NSPS as were for BAT. Thus, both new platforms and existing platforms face the same requirements. Since costs for new operations to design in compliance equipment should be as expensive as or less expensive than those for existing operations to retrofit the same compliance equipment, no significant barriers to entry are predicted to exist. Furthermore, since BAT was found to be economically achievable, NSPS is considered economically achievable.

F. Treatment, Workover, and Completion Fluids

1. BAT

No costs are incurred for Option 1. Costs of disposing of treatment, workover, and completion fluids under Option 2 are approximately $610,000 annually for all Gulf wells estimated to discharge treatment, workover, and completion fluids. A typical Gulf Coast well produces an average of 36 barrels of oil per day according to the 1993 Coastal Oil and Gas Questionnaire. At $18 per barrel, total annual production revenue at a typical well is estimated to be $237,000. Treatment, workover, and completion fluids disposal costs are estimated to be 0.74 percent of annual production revenues at a typical Gulf Coastal well, and no major impacts are expected as a result of either of the selected option (refer to Table 6). For this reason, EPA finds that the costs of Option 2 for treatment, workover, and completion fluids should be economically achievable for the Coastal Oil and Gas Industry.

2. NSPS

The options considered for NSPS for treatment, workover, and completion fluids are the same as those for BAT. Because NSPS is equivalent to BAT in the Gulf, new operations face the same or lower costs as existing operations. Thus, treatment, workover and completion fluids disposal costs for Option 2 will be 0.7 percent or less of annual production revenues at a typical Gulf coastal well. In Cook Inlet, there are no costs for zero discharge of this wastestream because this wastestream is commingled with produced water, and thus, the cost has already been accounted for in costing zero discharge for produced water. Option 2 NSPS requirements will not pose a significant barrier to entry. Furthermore, since BAT in the Gulf and NSPS in Cook Inlet is economically achievable, NSPS is economically achievable.

G. Cost-Effectiveness Analysis

In addition to the foregoing analyses, EPA has performed a cost-effectiveness analysis for the selected options for produced water; treatment, workover, and completion fluids; and drilling wastes. According to EPA's standard procedures for calculating cost-effectiveness, all the options considered for each waste stream have been ranked in order of increasing pounds-equivalent (PE) removed (see the introduction to this section for a discussion of pounds-equivalent, a methodology for putting pollutants of differing toxicity on a comparable basis.) Cost-effectiveness is calculated as the ratio of the incremental annual costs to the incremental pounds-equivalent removed under each option. So that comparisons of the cost-effectiveness among regulated industries can be made, annual costs for all cost-effectiveness analyses are reported in 1981 dollars.

In 1981 dollars, the incremental cost-effectiveness for the selected options are:

—$3/PE for produced water
—$0/PE for Option 1, $769/PE for Option 2 and $292/PE for Option 3 for drilling wastes
—$0/PE for Option 1 and $200/PE for Option 2 for treatment, workover, and completion fluids

H. Regulatory Flexibility

All of the firms expected to fail (0 to 12 firms) as a result of the proposed rule are small entities (i.e., they employ fewer than 500 employees), however, nearly all the firms operating in the Coastal region are small (approximately 372 out of an estimated 435 firms, or 86 percent are small firms). Thus 0 percent to 3 percent of small firms could potentially fail as a result of this rule. The high end of this estimate is very conservative because these firms might not fail; however, but data were unavailable to rule out the possibility. Thus these firms were considered to have the potential to fail as a result of the proposed rule. Due to data constraints, a cash flow analysis was not undertaken, but potential effects on working capital and equity were analyzed. In general, the average small firm that is currently discharging produced water or other wastes will experience a somewhat greater decline in working capital or equity than that for large firms. Among small dischargers, the median change in equity is 1.26 percent as compared with 0.02 percent for large firms, and the change in working capital is 4.54 percent, versus 0.05 percent for large firms. However, the typical small discharging firm will not experience a change in equity or working capital of more than 5 percent. Additionally most small firms are currently not discharging any wastes, thus will experience no change in equity or working capital. When these nondischarging firms are also considered, the median small firm operating in the coastal region will experience no change in equity or working capital. Thus EPA does not find that impacts on small firms will be disproportionately greater than those on large firms.

VIII. Non Water Quality Environmental Impacts

The elimination or reduction of one form of pollution has the potential to aggravate other environmental problems. Under sections 304(b) and 306 of the CWA, EPA is required to consider these non-water quality environmental impacts (including energy requirements) in developing effluent limitations guidelines and NSPS. In compliance with these provisions, EPA has evaluated the effect of these regulations on air pollution, solid waste generation and management, consumptive water use, and energy consumption. Because the technology basis for the limitation on drilling fluids and drill cuttings may require transporting the wastes to shore for treatment and/or disposal, adequate onshore disposal capacity for this waste is critical in assessing the options. Safety, and impacts of marine traffic on coastal waterways, were other factors also considered. EPA evaluated the non-water quality environmental impacts on a regional basis because the different regions each have their own unique considerations.

A. Drilling Fluids and Cuttings

The control technology basis for compliance with the options considered for the drilling fluids and drill cuttings wastestreams is a combination of product substitution, grinding followed by injection, and/or transportation of drilling wastes to shore for treatment and/or disposal. The non-water quality environmental impacts associated with the treatment and control of these wastes are summarized in Table 10. These non-water quality environmental impacts are those associated with drilling fluids and cuttings disposal and treatment alternatives only in Cook Inlet. All other coastal areas are currently achieving zero discharge of these wastes and, thus the control options cause no additional impacts. Non-water quality environmental impacts estimates are presented in more detail in the Coastal Technical Development Document.

TABLE 10.—NON-WATER QUALITY IMPACTS FOR DRILLING WASTE CONTROL OPTIONS

Options	Volume of waste transported to onshore disposal [3]	Volume of ground and injected waste (bbls)	Air emissions (tons/yr)	Fuel requirements (BOE) [2]/year
Option 1: Zero for all except BPT for Cook Inlet [1]	0	0	0	0
Option 2: Zero for all except for Cook Inlet with more stringent toxicity limit	93,984	0	9	1,700
Option 3: Zero for all	422,780	130,066	12.5	2,300

[1] Option one represents current standards such that no additional barrels of wastes or resulting air emissions or fuel requirements are required.
[2] BOE (barrels of oil equivalents).
[3] The volume of barged waste does not include wastes that would be ground and injected. The air emissions and fuel requirements presented in this table are a result of transporting these barged wastes and for grinding and injecting the rest.

1. Energy Requirements

Energy requirements for Options 2 and 3 were calculated by identifying those activities necessary to support onshore disposal of drilling wastes and injection at the platform. The only landfill available for disposal of drilling wastes in Cook Inlet is privately owned and operated. Access to this landfill is limited to only the two operators that own and operate it. The landfill, which is located on the west side of Cook Inlet, is only operated for four months in the summer because of climate conditions that are specific to Cook Inlet. Drilling wastes are first transported by supply boats from the platform to a temporary storage facility on the east side of Cook Inlet to be unloaded and temporarily stored. Barges are used to transport drilling wastes from the east to the west side of Cook Inlet. Trucks are then used to transport the muds and cuttings to the landfill. For the other operators in Cook Inlet, the technology basis for Option 3 (zero discharge) is grinding followed by injection at the platform. For Option 2 (which includes a 100,000 ppm (SPP) to 1,000,000 ppm (SPP) toxicity limitation that all operators would not be able to meet), the technology basis would be transportation and disposal to the lower contiguous United States for those operators not having access to Alaska landfills Option 2.

EPA used the volumes of drilling waste requiring onshore disposal to estimate the number of supply boat trips necessary to haul the waste to shore. Projections made regarding boat use included types of boats used for waste transport, the distance travelled by the boats, allowances for maneuvering, idling and loading operations at the drill site, and import activities at the marine transfer station. EPA estimated fuel required to operate the cranes at the drill site and import based on projections of crane usage. EPA determined crane usage by considering the drilling waste volumes to be handled and estimates of crane handling capacity. EPA also used drilling waste volumes to determine the number of truck trips required. The number of truck trips, in conjunction with the distance travelled between the marine transfer station and the disposal site, enabled an estimate of fuel usage. The use of land-spreading equipment at the disposal site was based on the drilling waste volumes and the projected capacity of the equipment. In evaluating the zero discharge requirement, EPA calculated for those operators that do not have access to the landfill in Cook Inlet, fuel requirements for grinding and injection equipment. The equipment evaluated included the pumps running the cuttings grinding system (the ball mills and conveyors) and the injection pumps. The methodology used to determine fuel consumption is further discussed in the Coastal Technical Development Document. Table 9 summarizes the incremental increase in energy requirements for the drilling fluids and drill cuttings options considered for this rule.

2. Air Emissions

EPA estimated air emissions resulting from the grinding and injection equipment systems, or the operation of boats, cranes, trucks and earth-moving equipment necessary to either dispose of drilling fluids and drill cuttings onshore or to grind and inject these wastes by using emission factors relating the production of air pollutants to time of equipment operation and amount of fuel consumed. The incremental increase in air emissions associated with the control options considered by EPA in this final rulemaking are presented in Table 9.

In developing regulations to control air pollution from OCS sources pursuant to the 1990 Clean Air Act Amendments, the EPA Office of Air Quality Planning and Standards estimated the air emissions associated with various stages of oil/gas resource development activities (''Control Costs Associated With Air Emission Regulations For OCS Facilities,'' Final Report September 30, 1991. Prepared by Mathtech, Inc. for EPA). In this study, EPA estimated levels of both controlled and uncontrolled emissions from exploration, development, and production operations. Information from this study was used to determine emissions from coastal operations independent of this rule. Nitrogen oxides (NO_X) emissions from exploratory drilling activities were estimated at 78 tons/operation. For comparison, the zero discharge requirement for all drilling activities in the Cook Inlet projected over the next seven years from scheduled promulgation is estimated at approximately 54 tons of NO_X for each well subject to the zero discharge limitations.

3. Solid Waste Generation and Management

The regulatory options considered for this rule will not cause generation of additional solids as a result of the treatment technology. However, as already discussed, spent drilling fluids and drill cuttings may be disposed of onshore to comply with these options.

There are currently no commercially operating disposal sites in Cook Inlet accepting drilling wastes. The only land disposal facility accepting drilling wastes from Cook Inlet operations is privately owned and operated. The lack of commercial disposal sites would require operators that do not own a land disposal facility to either transport the drilling wastes to the nearest known commercial disposal facility located in Idaho or inject the drilling wastes into underground formations.

Capacity estimates for the only available disposal facility in Cook Inlet show that this landfill has enough storage capacity to accept the volume of drilling fluids and cuttings (422,780 bbls over the next seven years following promulgation of this rule) that would be generated under Option 3 (zero discharge) from the two operators that it now serves. The volume of drilling wastes generated by these two operators under the zero discharge option represents about 71 percent of the excess available capacity at this landfill. The other Cook Inlet operators would not dispose of their drilling fluids and cuttings by landfilling, but rather by grinding and injection (See Section VI), which does not require land disposal.

Under Option 2, the estimated volume of drilling fluids and cuttings requiring land disposal is estimated to be approximately 17 percent of the total wastes generated over the next seven years following promulgation of this rule (or 17 percent of 552,846 bbls which is approximately to 94,000 bbls). This is based on the estimate of 83 percent compliance with a toxicity limitation between 100,000 ppm (SPP) and 1,000,000 ppm (SPP). EPA estimates that the two operators having access to the Cook Inlet landfill will send their portion of these wastes there (amounting to approximately 72,000 bbls), and as shown above, there would be sufficient landfill capacity to accommodate this as well as the zero discharge option. The other three operators not having access to the Cook Inlet landfill would most likely dispose of their drilling fluids and cuttings for this option (amounting to approximately 22,000 bbls) in a landfill available in Idaho, rather than grind and inject them (See Section VI), because this is less expensive than installing grinding and injection equipment for these smaller volumes. Because of this small volume of wastes, EPA assumed that there is ample landfill capacity in the lower 48 states for disposal of 22,000 bbls of wastes that would be generated over the seven years following the scheduled promulgation.

4. Consumptive Water Use

Since little or no additional water is required above that of usual consumption, no consumptive water loss is expected as a result of this rule.

5. Safety

EPA investigated the possibility of an increase in injuries and fatalities that would occur as a result of hauling additional volumes of drilling wastes to shore. EPA acknowledges that safety concerns always exist at oil and gas facilities, regardless of whether pollution control is required. EPA believes that the appropriate response to these concerns is adequate worker safety training and procedures as is practiced as part of the normal and proper operation of oil and gas facilities.

6. Increased Vessel Traffic in Cook Inlet

EPA estimates that a total of 231 boat trips would be required to comply with a zero discharge requirement. This estimate is for all drilling that will take place in the next seven years after expected promulgation of the rule. In actuality, EPA determined, from drilling schedules supplied by industry, that drilling would only occur for seven years after promulgation. Thus, these 231 boat trips equate to approximately 33 additional boat trips per year for seven years. EPA does not expect this to cause traffic problems in the Inlet. In fact, it will serve to provide service companies with additional work. EPA has calculated expected job gains associated with the manufacture, installation and operation of technologies required to comply with this rulemaking.

However, job gains could also be realized due to increased boat trips and related work required of service companies. These job gain estimates have not been quantified.

B. Produced Water

In assessing the non-water quality environmental impacts of the options considered for control of produced water, EPA projected the incremental increase in energy requirements and air emissions associated with the regulatory options considered. These non-water quality environmental impacts are presented in Table 11.

TABLE 11.—NON-WATER QUALITY ENVIRONMENTAL IMPACTS FOR PRODUCED WATER

Option	Fuel requirements (BOE/yr)		Total emissions (tons/yr)	
	BAT	NSPS[1]	BAT	NSPS[1]
1. BPT All	0	0	0	0
2. Oil and Grease	28,595	1,712	258	17
3. Zero Discharge; Cook Inlet BPT 48/72	258,946	5,948	2,799	64
4. Zero Discharge; Cook Inlet Oil and Grease	260,376	5,948	2,801	64
5. Zero Discharge All	343,759	5,948	2,899	64

[1] Impacts are associated only with new sources in the Gulf of Mexico. No new sources are expected in other coastal areas.

For small volume production facilities in the Gulf, produced water would be transported to commercial facilities for injection to comply with the options based on either gas flotation or injection because it is less expensive for smaller flows than installing injection or gas flotation equipment on-site. Produced water transportation (via barge or truck), and vacuum pumps to unload produced water at the commercial facilities are sources included in fuel use and air emissions calculations. For medium to large volume facilities in the Gulf and in Cook Inlet, either gas flotation or injection would be the technology bases to comply with the options. EPA determined the fuel requirements and air emissions for these technologies by evaluating:

• Power requirements to operate feed pumps and gas flotation devices
• Injection pumps and feed pumps for injection and pretreatment technology

Energy consumption for the different options was determined based on the produced water flowrates and the associated power requirements for operating treatment and injection systems.

EPA calculated the air emissions for each discharging facility by taking the product of specific emission factors, the usage in hours (that is, hours per year), and the horsepower requirements. EPA calculated total emissions for zero discharge based on the use of reciprocating natural gas fired engines as the power source for the injection pumps. According to industry, these engines are commonly used in coastal production facilities. Air emissions increases calculated for the produced water options include nitrogen oxides (NO_X), sulfur dioxide (SO_2), and hydrocarbons. See the Coastal Technical Development Document for more detail on the estimated compliance costs and EPA's calculation of pollutant removals and non-water quality environmental impacts.

The only increase in vessel waterway traffic due to these options would be for the small facilities that would be required to barge their produced waters to a commercial facility. This amounts to approximately 50 facilities out of a total of 216. Because vessels generally service several facilities on any given trip, EPA expects this increase to be small enough that it will be absorbed into current vessel operations. Additionally, use of the coastal waterways by the oil and gas industry accounts for less than 10 percent of all commercial traffic according to data from the Minerals Management Service. A slight increase in vessel traffic due to this rule would have negligible effect on the water traffic overall.

C. Treatment, Workover and Completion Fluids

The non-water quality environmental impacts associated with disposal of treatment, workover and completion fluids are the fuel requirements and air emissions resulting from transportation to commercial disposal where operators choose this method to comply with the rule. No incremental energy requirements and air emissions have been estimated for existing facilities that treat and discharge or inject treatment, workover and completion fluids onsite. This is because the control options for the facilities that treat and inject onsite are based on commingling treatment, workover and completion fluids with the produced water and, therefore, non-water quality environmental impacts associated with this activity have already been taken into account in assessing the impacts of control options for produced water.

Option 1, requiring BPT limits and zero discharge to freshwaters in Louisiana, would not cause additional non-water quality impacts because it reflects current practice (zero discharge of these fluids is a requirement in the Region VI general drilling permit).

Option 2, requiring limitations equal to those for produced water, would result in the consumption of approximately 1000 and 300 additional BOE per year, for BAT and NSPS respectively, and the generation of 12 and 3 tons of additional emissions per year for BAT and NSPS respectively.

IX. Executive Order 12866

Under Executive Order 12866, (58 FR 51735; October 4, 1993) the EPA must determine whether the regulatory action is ''significant'' and therefore subject to OMB review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a ''significant'' regulatory action. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendation will be documented in the public record for this rulemaking.

X. Executive Order 12875

Executive Order No. 12875 requires Federal Agencies to consider the impacts that unfunded mandates will have on state, local, or tribal governments. The coastal oil and gas industry is not associated with tribal governments, and the burden to state and local regulatory authorities is expected to be minimal, if not decreased, by the implementation of this rule.

The CWA, section 301 prohibits discharges of pollutants unless permitted under sections 402 or 404 of the CWA. Effluent limitations guidelines, new source performance standards and pretreatment standards are implemented through the National Pollutant Discharge Elimination System (NPDES) permits issued under section 402 of the CWA by EPA's Regions or, if delegated NPDES authority, the delegated states. Generally, coastal oil and gas facilities are permitted by EPA Regions, or in the case of Alabama, by the Alabama NPDES program, using general permits which cover an entire area specified in that permit. For example, Region VI's general permit for coastal drilling operations covers all coastal operations in Texas and Louisiana, except for a few facilities whose operations are noted in the permit. Alabama currently requires zero discharge in their permits for coastal oil and gas operations.

These proposed requirements, when promulgated, will be implemented via the existing regulatory structure and no additional burden is expected. In the absence of effluent limitations guidelines, establishing BAT, BCT, NSPS, PSES and PSNS, permit limitations are to be developed on as case-by-case ''Best Professional Judgement'' (BPJ) basis. In addition, all NPDES permits must incorporate state water quality standards. Once, these Coastal Guidelines are in place, the Regions will no longer be required to expend both in-house and contractor efforts in BPJ developments, and where zero discharge is required, the Regions and states will no longer be required to determine permit limitations based on water quality standards. Thus, these guidelines will actually serve to reduce the regulatory burden on the Regions and states that permit existing sources in the coastal oil and gas industry. As it could take approximately $100,000 for contractor support, and at least one in-house FTE per general permit development based on BPJ and water quality requirements, this could result in substantial savings. However, issuance of NSPS creates a class of facilities that is regulated as new sources which may need to be permitted by the regions and states. Because the number of new sources is projected to be very small and can be permitted by general permits, we expect this to be a minimal resource requirement.

Since the inception of the project in 1994, there have been periodic meetings with the industry and several trade associations, including the Louisiana and Texas Independent Oil and Gas Associations (TIOGA and LIOGA) and American Petroleum Institute (API) to discuss progress on the rulemaking. The Agency also has met with the Natural Resources Defense Council (NRDC) to discuss progress on this rulemaking. Because all of the facilities affected by this proposal are direct dischargers, the Agency did not conduct an outreach survey of POTWs.

The Agency also held a public meeting on July 19, 1994. The purpose of the meeting was to present the project status and discuss the technical options under consideration for this proposal. Representatives from industry trade associations, individual industry companies, state regulatory authorities the U.S. Department of Energy and Interior (Minerals Management Service) and the Sierra Club Legal Defense Fund attended.

The Agency will continue this process of consulting with state, local, and other affected parties after proposal in order to further minimize the potential for unfunded mandates that may result from this rule.

XI. Paperwork Reduction Act

The proposed coastal oil and gas effluent limitations guidelines and standards contain no new information collection activities, and therefore, no information collection request will be submitted to OMB for review in compliance with the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*

XII. Environmental Benefits Analysis

A. Introduction

The Water Quality Benefit Analysis (Benefit Analysis) evaluates the effect of current discharges and the benefits of proposed limitations for the coastal subcategory of the oil and gas extraction industry on the coastal environment. The benefit analysis considers two separate geographic areas: Gulf of Mexico (Louisiana and Texas) and Cook Inlet, Alaska. The benefit analysis examines potential impacts from current produced water discharges in both geographic areas, and from drilling fluids and drill cuttings discharges in Cook Inlet. Effect of drilling fluids and drill cutting discharges are not evaluated for Gulf of Mexico coastal operations since they are prohibited by state authorities and existing NPDES permits. Three types of benefits are analyzed: quantified and non-monetized, quantified and monetized, and non-quantified and non-monetized benefits.

Coastal waters maintain diverse ecosystems which act as spawning grounds, nurseries and habitats for important estuarine and marine species (finfish and shellfish); support highly valuable commercial and recreational fisheries; and provide critical habitat for seabirds, shore birds and terrestrial wildlife. The commercial fisheries in Texas and Louisiana (finfish, shrimp, crabs and oysters) were valued at $476 million in 1992. Commercial species spend a significant portion of their life cycle in bays and estuaries. The 1993 value of Cook Inlet commercial fisheries (finfish, clams,crabs and shrimp) was $48 million. Approximately $30 million of this total was from Upper Cook Inlet salmon fisheries. The estimated consumer surplus associated with Cook Inlet recreational fisheries is about $26 million per year (in 1993 dollars). In addition, personal use and subsistence fisheries provide food source and cultural values to Alaskan residents and Alaskan native populations. Coastal waters also serve as critical habitats for numerous federally designated endangered and threatened species (including 32 in coastal areas of Texas and Louisiana) , and migrating waterfowl.

Coastal waters are generally shallow, where tidal action has limited effect, and dilution and dispersion are more limited than offshore waters. Additionally, pollutants can migrate much more readily into sediments, where they may have long residence times. Consequently, these receiving environments are highly sensitive to pollutant discharges compared to open offshore areas. Many of the pollutants in coastal oil and gas discharges are either conventional pollutants, aquatic toxicants, human carcinogens, or human systemic toxicants. The impact of these pollutants on aquatic biota include acute toxicity; chronic toxicity; effects on reproductive functions; physical destruction of spawning and feeding habitats; and loss of prey organisms. In addition, many of these pollutants are persistent, resistant to biodegradation and accumulate in aquatic organisms. Chemical contamination of aquatic biota may also directly or indirectly impact local aquatic and terrestrial wildlife and humans consuming exposed biota.

Conventional pollutants, such as TSS and oil & grease can have adverse effects on human health and environment. For example, habitat degradation can result from increased suspended particulate matter that reduces light penetration and thus primary productivity. Suspended solids in the water column can have a direct effect on the fish either killing them, or reducing their growth rate and/or resistance to disease, preventing successful development of fish eggs and larvae, modifying fish movement and migration and reducing the abundance of food available to fish. Settleable materials which blanket the bottom of the water bodies cause benthic smothering, damage invertebrate populations and can alter spawning grounds and feeding habitat. Oil and grease can have lethal effect on fish, by coating surface gills causing asphyxia, or depleting oxygen levels due to excessive biological demand, or reducing reaeration because of surface film. Oil and grease can also have detrimental effects on waterfowl by destroying the buoyancy and insulation of their feathers. Bioaccumulation of oil substances can cause human health problems including tainting of fish and bioaccumulation of carcinogenic polycyclic aromatic compounds.

Benefits of this proposed rule include elimination of toxic, conventional, and nonconventional pollutants, or reduction to levels below those considered to impact receiving water's biota, and elimination or reduced impacts on human health. Potential benefits may ultimately include reduced aquatic habitat degradation; improved recreational fisheries; improved subsistence and personal use fisheries (important to low-income anglers and Alaska's Native anglers, etc.); improved commercial fisheries; improved aesthetic quality of waters; improved recreational opportunities; and decreased harm to threatened or endangered species in Gulf of Mexico and Cook Inlet.

B. Quantitative Estimate of Benefits

(1) Gulf of Mexico. The Gulf of Mexico benefits associated with produced water include: (a) non-monetized benefits (*i.e.*, (i) review of case studies of environmental impacts of produced water that document adverse chemical and biological impacts resulting from its discharge into coastal waters in the Gulf of Mexico; (ii) modeled water quality benefits expressed as reduction/elimination in exceedances of human health or aquatic life state water quality standards; and (iii) estimated reduction of total point source toxic loading contribution to Texas and Louisiana estuarine drainage systems, and (b) monetized benefits (*i.e.*, (i) estimated reduction of carcinogenic risk from consumption of seafood contaminated with Ra^{226} and Ra^{228} based on limited observations and modeled levels; and (ii) estimated ecological benefits of zero discharge of produced water.))

(a) Quantified Non-Monetized Benefits.

(i) Documented Case Studies. A comprehensive review of available data identified 25 study sites (12 in Louisiana and 13 in Texas) that examined impacts of produced water discharges on coastal environment. The majority of evaluated study sites are in water depths less than 3 meters, and include variable environments (*i.e.*, wetlands, saltmarshes, and fresh or brackish marshes), and both relatively low and high energy areas. The documented impacts show elevated hydrocarbons and metals in water column and sediments, and reveal impacts on biota (*i.e.*, depressed community structure such as abundance or diversity) up to 1,000 meters (and more) from the produced water discharge. The salinity effects are typically detected up to 300 meters from the discharge, and up to 800 meters in dead-end canals. A benthic dead zone (no benthic fauna) is documented up to 15 meters and severely depressed benthic communities are noted to 150 to 400 meters from produced water outfalls.

(ii) Projected Water Quality Benefits. The effects of toxic pollutants in current (BPT) produced water discharges on receiving water quality and benefits of proposed effluent guidelines are evaluated. Plume dispersion modeling is performed to project in-stream concentrations of 66 pollutants (representing subcategory-wide produced water discharge) at the edge of the state-prescribed mixing zones for Texas and Louisiana at one and three meters water depths. The in-stream concentrations are compared to Texas and Louisiana state standards; Texas has standards for 12 of the pollutants and Louisiana for 14. The results based on the mean discharge rate show one pollutant (silver) in Texas exceeds its chronic standard at the one meter depth; in Louisiana, one pollutant (copper) exceeds two acute standards (daily average and maximum), two pollutants (copper and lead) exceed two chronic standards, and one pollutant (benzene) exceeds two human health standards at the one meter depth, and at three meter depth one pollutant (copper) exceeds its acute standard, and one pollutant (benzene) exceeds two human health standards at the three meter depth. The proposed BAT zero discharge option would eliminate all projected exceedances.

(iii) Projected Reduction of Point Source Toxic Loading Contribution to Texas and Louisiana Estuarine Drainage Systems. The watershed pollutant loadings from produced water are compared to other industrial and municipal point sources (*i.e.*, excluding pollutant loadings from nonpoint sources and atmospheric deposition) for Texas and Louisiana estuarine drainage systems. At the current (BPT) discharge level, produced water in Texas contributes about 20 percent, and in Louisiana about 60 percent of total point source mass pollutant loadings into their respective watersheds. The proposed zero discharge would eliminate produced water pollutant loading contribution to the Texas and Louisiana coastal watershed.

(b) Quantified Monetized Benefits. (i) Projected Cancer Risk Reduction Benefits. Upper bound individual cancer risks from consuming fish contaminated with Ra^{226} and Ra^{228} from current produced water discharges are estimated for recreational and subsistence anglers, and aggregate human cancer risks are projected and monetized. Risks are estimated using two types of data: (1) Measured field seafood data (*i.e.*, because background levels could not be adequately determined average Ra^{226} and Ra^{228} levels were used based on field samples of fish, crabs and oysters collected within 3,000 meters of produced water discharges in coastal subcategory areas of Louisiana), and (2) modelled effluent data (*i.e.*, using current subcategory-wide produced water concentrations of Ra^{226} and Ra^{228} and plume dispersion model at mean outfall discharge rates to estimate Ra^{226} and Ra^{228} levels in seafood). [Using the estimated Ra^{226} and Ra^{228} concentrations in seafood, EPA estimates individual cancer risks assuming two different consumption rates of 147.3 g/day for subsistence anglers and 15 g/day for recreational anglers]. In addition, all individual cancer risks are adjusted by factors of 0.2 and 0.75 to account for ingestion of seafood from locations some of which are not contaminated with the Ra^{226} and Ra^{228} in coastal produced water discharges. Projected individual cancer risks for both risk assessment approaches are at 10^{-4} level for subsistence anglers, and at 10^{-6} level recreational anglers. The proposed zero discharge of produced water will eliminate these estimated cancer risks over time. Based on measured field data, the proposed BAT is projected to eliminate 1.1 to 4.3 annual cancer cases and the monetized benefits from cancer cases avoidance are projected to range from $2.3 to $43 million. Using the modelling approach, the proposed BAT is projected to eliminate 1.2 to 4.6 cancer cases per year, resulting in monetized benefits in $ 2.4 to $46 million per year.

The temporal dynamics of both impacts and benefits assessments is relevant to the human health risk assessment. For the assessments of cancer reduction benefits, the methodology is consistent with estimating costs for the rule, using a one-year ''snap-shot'' approach. Allocating the full value of annual benefits within one year following cessation of produced water discharges may appear to over-estimate potential annual benefits in cases where incomplete recovery has occurred. However, in such cases where impacts are incompletely recovered, a consideration of total impact would need to include any impacts expected to occur beyond that year. This analysis does not attempt to identify or allocate benefits on a yearly basis, but merely averages total benefits so that monetized benefits may be compared to costs that are developed using the same approach.

(ii) Projected Ecological Benefits for Texas and Louisiana Bays. A potential ecological benefit of zero discharge of produced water in Texas and Louisiana coastal areas is projected from a Trinity Bay case study. This study shows that measures of total benthic abundance and species richness are depressed by discharges, up to distances between 1.7 kilometers and 4 kilometers from the point of discharge. (Data on abundance of other species, such as waterfowl were not collected.) Taking into account the severity of these impacts at different distances, the equivalent acreage affected in this case study ranges from 200 to 2,817 acres. Extrapolating from this case study to the other sites that would be affected by this rule, EPA estimates that the total Texas and Louisiana acreage affected ranges from 14,607 acres to 195,488 acres. EPA identified numerous values for an acre of wetland but none were marginal estimates for Texas or Louisiana, and some did not net out the cost of recreational use. A literature review for wetland value estimates conducted for Mineral Management Services (MMS) in 1991, reports that different studies have estimated recreational and commercial wetland values for coastal Louisiana ranging from $57 to $940 per acre per year (with a median value of $410 per acre per year) in 1990 dollars. Using this range of values, the estimated increase of Texas and Louisiana Bay recreational values ranges from $0.8 million to $184 million per year in 1990 dollars ($1.0 million to $210 million in 1994 dollars). These per acre estimates are consistent with the estimated average recreational value of the acreage of Galveston Bay, which ranges from $336 to $730 per acre. (The Galveston Bay estimates do not net out the cost to recreational users of using the resource.) These estimates may not be marginal values as they are calculated from the total recreational value of Galveston Bay and total acreage of the Bay. There may be concern that the value of wetland recovery diminishes as the amount of recovered acreage increases and therefore these average values would overstate the relevant marginal values by an unknown amount. As these studies use different estimation methods, cover different types of wetlands, marshes and coastal waters which may differ from those affected by this rule, and generally reflect average values rather than the social valuation of small (marginal) changes in acreage, EPA solicits comments on the appropriateness of this benefit analysis and requests data on marginal values of wetlands, in particular in Texas and Louisiana.

(iii) Total Monetized Benefits. EPA estimates that total monetized benefits (*i.e.* combining cancer risk reduction and ecological benefits) resulting from proposed zero discharge of produced water range from approximately $3.2 to $230 million per year in 1990 dollars ($3.7 million to $263 million in 1994 dollars).

(2) Cook Inlet. Quantified benefits analyzed in Cook Inlet include non-monetized quantified benefits associated with proposed regulations of produced water and drilling fluids and drill cuttings. These benefits include modeled water quality benefits expressed: (a) as a reduction of mixing zone needed for produced water discharges to meet Alaska state water quality standards, and (b) as a reduction or elimination in exceedances of Alaska state water quality standards at the edge of mixing zone from drilling fluids and drill cutting discharges.

(a) Produced Water. The effects of toxic pollutants in current (BPT) produced water discharges on receiving water quality and benefits of proposed effluent guidelines are evaluated. Plume dispersion modeling is performed to project in-stream concentration of 21 pollutants at the edge of the mixing zones from eight outfalls representing Cook Inlet produced water discharge; the in-stream concentrations are then compared to the Alaska's state limitations. Unlike the Gulf of Mexico, Alaska state requirements do not have spatially-defined mixing zones. (Alaska determines the extent of the mixing zone needed to achieve compliance with water quality standards and evaluates reasonableness of this calculated mixing zone). The water quality assessment for Cook Inlet therefore determines the spatial extent of mixing zones needed for each evaluated outfall to meet all state standards at current discharge and at the proposed BAT. For the eight outfalls modeled, the distance from each facility where all state standards are met ranges from within 50 feet to 2,500 meters at current (BPT) level, and from within 50 feet to 2,000 meters at proposed BAT.

(b) Drilling Fluids and Drill Cuttings. Discharges of drilling fluids and drill cuttings are modelled using Offshore Operator's Committee (OOC) Mud Discharge Model to project in-stream concentrations of 19 pollutants in water column at the edge of a 100 meter mixing zone. The projected pollutant concentrations are then compared to the Alaska state water quality standards. The discharge rates are modeled in accordance with the maximum discharge rates allowable under the existing NPDES general permit for Cook Inlet (1,000 bph in water depths exceeding 40 meters; 750 bph in water depths from 20 to 40 meters; and 500 bph in water depths from 5 to 20 meters). Discharges are prohibited in waters between the shore and the 5 meter isobath. The modeling results show four standards are exceeded (human health standards for beryllium and fluorene and the drinking water standards for aluminum and iron) at 40 meter water depth; at 20 meters water depth five standards are exceeded (human health standards for beryllium, fluorene, and phenanthrene, and drinking water standards for aluminum and iron); and six standards are exceeded at the 10 meters water depth (human health standards for beryllium, fluorene, and phenanthrene, and drinking water standards for aluminum, antimony, and iron) at both current BPT discharge and the alternative BAT Option 2 which would allow discharge of drilling fluids and drill cuttings with certain limitations. The zero discharge option (Option 3) would eliminate all projected exceedances.

C. Description of Non-Quantified Benefits

The Benefit Analysis attempts to quantify, and whenever appropriate, to monetize specific environmental benefits that may result from the options proposed for this rule. However, some of the potential benefits could not be quantified or monetized because of the lack of data, or because sufficient information to define the causal relationship between coastal oil and gas production activities and environmental effects is not available. The evaluated non-quantified benefits include: (1) an analysis of environmental equity issues related to this rulemaking; (2) effects on threatened or endangered species and migratory waterfowl, and potential benefits from the proposed rule for ecosystem health for coastal areas of Gulf of Mexico and Cook Inlet.

(1) An Analysis of Environmental Equity Issues. An analysis of potential impacts on socioeconomic and ethnic groups in coastal areas of Texas, Louisiana, and Cook Inlet conducted to address environmental equity issues related to the discharges from coastal oil and gas facilities indicates that the subsistence and personal use of fisheries in both geographic areas may be appreciable, indicating potential environmental equity concerns for low income subsistence and personal use anglers including Alaska's Native populations. These socioeconomic and ethnic groups are known to be frequent recreational or subsistence anglers and are consuming a high rate of seafood, and could consequently be at higher than average risk, providing they consume seafood that may be contaminated with coastal oil and gas pollutants. The subsistence and personal use fisheries in these areas also provide food sources that would otherwise have to be purchased elsewhere. In addition, Cook Inlet fisheries are of cultural value to Alaskan Native populations in that they allow the continuance of a traditional lifestyle dependent on the natural resources of the Inlet. A zero discharge and control of discharges of produced water, and zero discharge of drilling fluids and drill cuttings, and well treatment, workover and completion fluids discharges would reduce these impacts.

(2) Effects on Threatened and Endangered Species. The proposed regulation may also have beneficial effects on 32 threatened and endangered species in coastal area of Texas and Louisiana (such as Brown Pelican, Hawksbill Sea Turtle, Leatherback Sea Turtle, Ocelot, and others) that use these areas as part of their habitat. The Upper Cook Inlet is an important pathway for spawning fish and nonendangered mammals which are resident or occur seasonally in Cook Inlet including sea lion, fur seal, harbor seal, sea otter and beluga whale. The Cook Inlet area is also a critical habitat for seabirds, shorebirds, and migrating waterfowl, including the Cackling Canada Goose, Pacific Black Brant, Emperor Goose, and Tule Goose. There are at least four endangered cetacean species which may occur in or near Cook Inlet. These include the humpback whale, fin whale, sei whale, and gray whale. Endangered avian species which may occur as migrants in or near Cook Inlet include the short-tailed albatross, American peregrine falcon, and Arctic peregrine falcon. Control of produced water and treatment, workover, and completion fluids discharges and zero discharge of drilling fluids and drill cuttings, would reduce these impacts.

D. EPA Region VI Production Permit

The benefits of the proposed rule evaluated in the benefit analysis are based on discharges and discharge locations that were projected for the proposed guidelines (without the published final Region 6 NPDES General permits regulating produced water discharges to coastal waters in Louisiana and Texas in effect). Because of the close timing of the publication of these final General permits and the proposed effluent guidelines, little opportunity for in-depth re-analysis of environmental benefits occurred. The approach selected is to proportionate quantified benefits based on a simple flow proportion (*i.e.*, the 29 percent share of produced water flow), attributable to the facilities excluded from coverage under the General permits but covered by the proposed effluent guidelines. Using this approach, EPA estimates that with the Region 6 General permits final, quantified monetized benefits may be in the $0.9 to $67 million range in 1990 dollars ($1.1 to $76 million in 1994 dollars). EPA will re-evaluate environmental benefits of the coastal oil and gas subcategory effluent guidelines upon promulgation of the final rule.

XIII. Regulatory Implementation

A. Toxicity Limitation for Drilling Fluids and Drill Cuttings

Under the alternative option EPA considered for drilling fluids and drill cuttings, EPA would establish a toxicity limit for this waste stream. The toxicity limitation would apply to any periodic blowdown of drilling fluid as well as to bulk discharges of drilling fluids and drill cuttings systems. The reader is referred to the Offshore Guidelines (58 FR, March 4, 1993, page 12502) for an explanation of the regulatory implementation for the toxicity limit.

B. Diesel Prohibition for Drilling Fluids and Drill Cuttings

Under EPA's alternative option for drilling fluids and drill cuttings, diesel oil and muds and cuttings contaminated with diesel would be prohibited from discharge from Cook Inlet oil platforms. The reader is referred to the Offshore Guidelines (58 FR 12502) for a discussion on the implementation of this requirement.

C. Upset and Bypass Provisions

A recurring issue of concern has been whether industry guidelines should include provisions authorizing noncompliance with effluent limitations during periods of ''upsets'' or ''bypasses''. The reader is referred to the Offshore Guidelines (58 FR 12501) for a discussion on upset and bypass provisions.

D. Variances and Modifications

Once this regulation is in effect, the effluent limitations must be applied in all NPDES permits thereafter issued to discharges covered under this effluent limitations guideline subcategory. Under the CWA certain variances from BAT and BCT limitations are provided for. A section 301(n) (Fundamentally Different Factors) variance is applicable to the BAT and BCT and pretreatment limits in this rule. The reader is referred to the Offshore Guidelines (58 FR 12502) for a discussion on the applicability of variances.

E. Synthetic Drilling Fluids

During the Offshore Oil and Gas Guidelines rulemaking, several industry commenters noted recent developments in formulating new (synthetic) drilling fluids as substitutes for the traditional water-based or oil-based fluids. The newer drilling fluids provide improved environmental and operational benefits when compared to many of the traditional fluids being used. The industry commenters contended that the new drilling fluids are not being used due to potential interpretation of effluent guidelines and permit limitations. Prohibitions on the use of oil-based fluids and inverse emulsions were identified as potential barriers to use. Commenters also specifically identified the sheen test, which is used to prohibit the discharge of fluids and cuttings containing free oil, as giving false positive results due to a discoloration which may occur when cuttings containing small amounts of some of the synthetic fluids are discharged.

Since the promulgation of the Offshore Guidelines, data have been submitted to document the enhanced environmental performance of synthetic fluids. These data show lower toxicity than several of the generic fluids used as the basis for the offshore toxicity limit of 30,000 ppm (SPP). Results of laboratory and field (seabed) evaluations of the biodegradation of one synthetic fluid demonstrated good biodegradation. Case histories of field use have documented enhanced operational and environmental performance, which can include reductions in waste generated and improvement of non-water quality impacts. Laboratory data have indicated no detectable priority pollutants to be present in synthetic fluids.

In the preamble to the March 4, 1993, final Offshore Guidelines (58 FR 12496), EPA identified several issues raised by commenters for which additional information was solicited. While EPA wishes to encourage the use of less toxic drilling fluids, EPA was concerned that without a substitute for the static sheen test, it would not be possible to enforce the no free oil limit. EPA also solicited specific data concerning the toxicity of new synthetic drilling fluids. Subsequently, several industry companies have submitted additional information. EPA has reviewed this information and is conducting additional work to further evaluate the issues. This work is related to the analytical capability to identify the synthetic fluids versus diesel, mineral or crude (formation) oils which may cause a sheen when used fluids or cuttings are discharged and the toxicity of the synthetic fluids. Results of the submitted analytical methods investigations, summarized gas chromatography mass copy (GC/MS) identification of polyalphaolafin synthetic fluids. The usefulness and limitations of the methods were discussed. Use of GC equipment shows promise for detecting low concentrations of oil in synthetic fluids, *e.g.*, less than 1 percent, but requires further evaluation. Based on the results of the initial work and work performed as part of the final Offshore Guidelines to differentiate between mineral oil and diesel oil (58 FR 12502), the ''methods for the determination of Diesel, Mineral and Crude Oils in Offshore Oil and Gas Industry Discharges'' (EPA 821–R–92–008) may be useful, with or without slight modifications, as an alternative or verification step to the free oil and diesel oil discharge prohibitions.

EPA solicits data on the use to-date of synthetic fluids and any data, including well logs, toxicity and analytical methods testing and in-situ seabed and water column physical, chemical and biological testing. EPA will evaluate all submitted data, including information in the offshore rulemaking record, in order to assess the environmental and performance benefits that could be achieved by using synthetic fluids, and take those regulatory actions that may be appropriate to mitigate or eliminate barriers to using these fluids.

F. Removal Credits for Indirect Dischargers

Many industrial facilities discharge large quantities of pollutants to POTWs where their wastewaters mix with wastewater from other sources, domestic sewage from private residences and run-off from various sources prior to treatment and discharge by the POTW. Industrial discharges frequently contain pollutants that are generally not removed as effectively by treatment at the POTWs as by the industries themselves.

The introduction of pollutants to a POTW from industrial discharges may pose several problems. These include potential interference with the POTW's operation or pass-through of pollutants if inadequately treated. As discussed, Congress, in section 307(b) of the Act, directed EPA to establish pretreatment standards to prevent these potential problems. Congress also recognized that, in certain instances, POTWs could provide some or all of the treatment of an industrial user's wastewater that would be required pursuant to the pretreatment standard. Consequently, Congress established a discretionary program for POTWs to grant ''removal credits'' to their indirect dischargers. The credit, in the form of a less stringent pretreatment standard, allows an increased concentration of a pollutant in the flow from the indirect discharger's facility to the POTW.

Section 307(b) of the CWA establishes a three-part test for obtaining removal credit authority for a given pollutant. Removal credits may be authorized only if (1) the POTW ''removes all or any part of such toxic pollutant,'' (2) the POTW's ultimate discharge would ''not violate that effluent limitation, or standard which would be applicable to that toxic pollutant if it were discharged'' directly rather than through a POTW and (3) the POTW's discharge would ''not prevent sludge use and disposal by such [POTW] in accordance with section [405].* * *'' Section 307(b).

EPA has promulgated removal credit regulations in 40 CFR 403.7. The United States Court of Appeals for the Third Circuit has interpreted the statute to require EPA to promulgate comprehensive sewage sludge regulations before any removal credits could be authorized. *NRDC* v. *EPA*, 790 F.2d 289, 292 (3rd Cir. 1986) *cert. denied.* 479 U.S. 1084 (1987). Congress made this explicit in the Water Quality Act of 1987 which provided that EPA could not authorize any removal credits until it issued the sewage sludge use and disposal regulations required by section 405(d)(2)(a)(ii).

Additional discussion of the availability of removal credits is contained in the Coastal Technical Development Document. This rule proposes to establish pretreatment standards for existing and new sources as zero discharge for drilling fluids and drill cuttings; produced water; well treatment, workover, and completion fluids; and deck drainage, and EPA's pretreatment regulations at 40 CFR 403.7(a)(i) limit such authorization to when the POTW demonstrates and continues to achieve consistent removal of the pollutant in accordance with 403.7(b), it is highly unlikely that removal credits would be available for these discharges.

EPA welcomes comment on when and how removal credits may be authorized for the pollutants in the circumstances of the coastal oil and gas subcategory.

XIV. Related Rulemakings

In addition to these Coastal Guidelines, EPA is in the process of developing other regulations that specifically affect the oil and gas industry. These other rulemakings, summarized below, are in the developmental stages, and have not, as yet, been proposed. EPA's offices are coordinating their efforts with the intent to monitor these related rulemakings to assess their collective costs to industry.

A. National Emission Standards for Hazardous Air Pollutants

National emission standards for hazardous air pollutants (NESHAP) are being developed for the oil and gas production industry by EPA's Office of Air Quality, Planning and Standards (OAQPS), under authority of section 112 (d) of the Clean Air Act as amended in 1990. Section 112 (d) of the Clean Air Act directs the EPA to promulgate regulations establishing hazardous air pollutant (HAP) emissions standards for each category of major and area sources that has been listed by EPA for regulation under section 112 (c). The 189 pollutants that are designated as HAP are listed in section 112 (d). For major sources, or facilities which emit 10 or more tons per year (TPY) of an individual HAP pollutant or 25 or more TPY of multiple HAPs, the air emission standards are based on ''maximum achievable control technology'' or MACT.

Major sources within the coastal oil and gas subcategory have been identified by OAQPS as stand alone glycol dehydrators, tank batteries, gas plants, and offshore production platforms. In most cases, OAQPS believes that, in order to be a major source, a coastal production facility must have glycol dehydrators located on-site: a production facility alone may not produce enough emissions to be classified as a major source.

EPA plans to propose MACT standards for the oil and gas industry by June 1995 and promulgate them by June 1996. OAQPS estimates that the total cost of these standards will be $13 million. Offshore production platforms are under the jurisdiction of the Minerals Management Service and thus, are not affected by these MACT Standards. EPA solicits information regarding the percentage of coastal oil and gas operations that will be impacted by this rule.

2. Area of Review Requirements for Injection Wells

The Safe Drinking Water Act of 1974 (SDWA) charges EPA with protecting underground sources of drinking water (USDWs). As part of this mandate, EPA developed a program, known as the Underground Injection Control Program (UIC), to regulate the underground injection of produced water, and promulgate regulations concerning the construction, operation, and closure of Class II injection wells. Such regulations were originally promulgated in 1980 (45 FR 42500, June, 24, 1980).

As a result of a recent 5-year study on the effectiveness of these regulations, EPA concluded that more detailed minimum national standards, than those promulgated in 1980, are necessary to prevent endangerment of USDWs.

EPA is currently in the process of developing such national standards that would establish:

* A minimum national standard for well construction,

* More frequent mechanical integrity testing when the construction of a well does not meet that minimum standard, and

* A requirement for Area of Review studies for wells located in areas where USDWs are subject to significant risk of indirect flow via improperly constructed or abandoned wells.

The schedule for proposal and promulgation of this rulemaking is not specified. Early estimates are that these UIC requirements would cost less than $50 million per year for the entire U.S. oil and gas industry for the first 5 years after promulgation, and are expected to decrease after 5 years.

It is not known at this time what percentage of this cost will be incurred by the coastal oil and gas industry. EPA solicits comment regarding this.

3. Spill Prevention, Control, and Countermeasure

EPA's Oil Pollution Prevention regulation at 40 CFR part 112, otherwise known as the Spill Prevention, Control, and Countermeasure (SPCC) regulation was promulgated in 1973 under section 311 (j) of the CWA. The SPCC regulation applies to all oil extraction and production facilities that have an oil storage capacity above certain thresholds (*i.e.* an overall aboveground oil storage capacity greater than 1,320 gallons or greater than 660 in a single container, or an underground oil storage capacity of greater than 42,000 gallons) and are located such that a discharge could reasonably be expected to reach U.S. waters. EPA estimates that there are approximately 435,000 SPCC-regulated facilities. Approximately 3,000 of these facilities are either coastal or offshore facilities.

Under the SPCC regulations, facility owners or operators are required to prepare and implement written SPCC plans that discuss conformance with procedures, methods, and equipment and other requirements to prevent discharge of oil and to contain such discharges.

On July 1, 1994, (59 FR 34070, July 1, 1994) EPA issued a final rule for certain onshore facilities to prepare, submit to EPA, and implement plans to respond to a worst case discharge of oil to meet section 4202(a) of the Oil Pollution Act (OPA). EPA is in the process of developing requirements to meet Section 420.2(a) of OPA specifically for coastal facilities (Note: Coastal and offshore facilities in the SPCC program are collectively referred to as ''offshore''. However, this current rulemaking is specifically with respect to facilities landward of the inner boundary of the territorial seas, and that are not onshore.) These regulations will, among other things, require that owners or operators of all coastal facilities prepare and submit to the Federal government a plan for responding to a worst case discharge of oil.

EPA plans to propose these requirements by 1995, and promulgate them by 1996. Costs to the industry to comply with these requirements are as yet unknown. EPA solicits information regarding the storage capacities of coastal oil production facilities to determine the percentage of this industry under the Coastal Oil and Gas subcategory that would be affected by the SPCC regulations.

XV. Solicitation of Data and Comments

EPA encourages public participation in this rulemaking and invites comments on any aspect of these proposed regulations. The EPA asks that comments address any perceived deficiencies in the record of this proposal and that suggested revisions or corrections be supported by data where possible. The preceding parts of this notice identify specific areas where comments are solicited. In addition, EPA particularly requests comments and information on the following:

(1) Combining the Onshore and Coastal Subcategories

EPA's proposed coastal rule requires zero discharge for all drilling fluids and cuttings, as well as zero discharge for all produced waters except from Cook Inlet operations. Because the effluent limitations for the onshore subcategory of the oil and gas industry require zero discharge for all oil and gas wastes (44 FR 22069, April 13, 1979), EPA is considering the appropriateness of combining these two subcategories for regulation of the major wastestreams. Combining the subcategories would not only simplify the rule itself but, could result in reduction of administrative burden in permit development, and facility location determination; EPA solicits comment on the appropriateness of combining these two subcategories.

XVI. Background Documents

The basis for this regulation is detailed in two major documents, each of which is supported in turn by additional information and analyses in the rulemaking record. EPA's technical foundation for the regulation is detailed in the Development Document for Proposed Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. EPA's economic analysis is presented in the Economic Impact Analysis of Proposed Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Offshore Oil and Gas Industry. These documents are available from the Office of Water Resource Center. (See **ADDRESSES**) The public record for this rulemaking is available for review at EPA's Water Docket. (See **ADDRESSES**)

Appendix A to the Preamble—Abbreviations, Acronyms, and Other Terms Used in This Document

Act—Clean Water Act.

Agency—Environmental Protection Agency.

BADCT—The best available demonstrated control technology, for new sources under section 306 of the Clean Water Act.

BAT—The best available technology economically achievable, under section 304(b)(2)(B) of the Clean Water Act.
bbl—barrel, 42 U.S. gallons.
bpd—barrels per day.
bpy—barrels per year.
BCT—Best conventional pollutant control technology under section 304(b)(4)(B) of the Clean Water Act.
BMP—Best management practices under section 304(e) of the Clean Water Act.
BOD—Biochemical oxygen demand.
BOE—Barrels of oil equivalent.
BPT—Best practicable control technology currently available, under section 304(b)(1) of the Clean Water Act.
CFR—Code of Federal Regulations.
Clean Water Act—Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 *et seq.*).
Conventional pollutants—Constituents of wastewater as determined by section 304(a)(4) of the Clean Water Act, including, but not limited to, pollutants classified as biochemical oxygen demanding, suspended solids, oil and grease, fecal coliform, and pH.
CWA—Clean Water Act.
Direct discharger—A facility which discharges or may discharge pollutants to waters of the United States.
EIA—Economic Impact Analysis.
EPA—Environmental Protection Agency.
Indirect discharger—A facility that introduces wastewater into a publicly owned treatment works.
IRR—Internal Rate of Return.
LC50—The concentration of a test material that is lethal to 50 percent of the test organisms in a bioassay.
mg/l—milligrams per liter.
Nonconventional pollutants—Pollutants that have not been designated as either conventional pollutants or priority pollutants.
NORM—Naturally Occurring Radioactive Materials.
NPDES—The National Pollutant Discharge Elimination System.
NPV—Net Present Value.
NSPS—New source performance standards under section 306 of the Clean Water Act.
OCS—Offshore Continental Shelf.
OMB—Office of Management and Budget.
POTW—Publicly Owned Treatment Works.
ppm—parts per million.
Priority pollutants—The 65 pollutants and classes of pollutants declared toxic under section 307(a) of the Clean Water Act.
PSES—Pretreatment standards for existing sources of indirect discharges, under section 307(b) of the Clean Water Act.
PSNS—Pretreatment standards for new sources of indirect discharges, under sections 307 (b) and (c) of the Clean Water Act.
SIC—Standard Industrial Classification.
SPP—Suspended particulate phase.
TSS—Total Suspended Solids.
Coastal Technical Development Document—Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category.
Offshore Technical Development Document—Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category.
U.S.C.—United States Code.

List of Subjects in 40 CFR Part 435

Environmental protection, Oil and gas extraction, Pollution prevention, Waste treatment and disposal, Water pollution control.

Dated: January 31, 1995.

Carol M. Browner,
Administrator.

For the reasons set forth in the preamble, 40 CFR part 435 is proposed to be amended as follows:

PART 435—OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

1. The authority citation for part 435 is revised to read as follows:

Authority: 33 U.S.C. 1311, 1314, 1316, 1317, 1318 and 1361.

2. Subpart A is proposed to be amended by revising § 435.10 to read as follows:

Subpart A—Offshore Subcategory

§ 435.10 Applicability; description of the offshore subcategory.

The provisions of this subpart are applicable to those facilities engaged in field exploration, drilling, well production, and well treatment in the oil and gas industry which are located in waters that are seaward of the inner boundary of the territorial seas (''offshore'') as defined in section 502(g) of the Clean Water Act.

3. Subpart G consisting of § 435.70 is proposed to be added to read as follows:

Subpart G—General Provisions

§ 435.70 Applicability.

(a) *Purpose.* This subpart is intended to prevent oil and gas facilities subject to this part from circumventing the effluent limitations guidelines and standards applicable to those facilities by moving effluent produced in one subcategory to another subcategory for disposal under less stringent requirements than intended by this part.

(b) *Applicability.* The effluent limitations and standards applicable to an oil and gas facility shall be determined as follows:

(1) An oil and gas facility, operator, or its agent or contractor may move its wastewaters from a facility located in one subcategory to another subcategory for treatment and return it to a location covered by the original subcategory for disposal. In such case, the effluent limitations guidelines, new source performance standards, or pretreatment standards for the original subcategory apply.

(2) An oil and gas facility, operator, or its agent or contractor may move its wastewaters from a facility located in one subcategory to another subcategory for disposal or treatment and disposal, provided:

(i) If an oil and gas facility, operator or its agent or contractor moves wastewaters from a wellhead located in one subcategory to another subcategory where oil and gas facilities are governed by less stringent effluent limitations guidelines, new source performance standards, or pretreatment standards, the more stringent effluent limitations guidelines, new source performance standards, or pretreatment standards applicable to the subcategory where the wellhead is located shall apply.

(ii) If an oil and gas facility, operator or its agent moves effluent from a wellhead located in one subcategory to another subcategory where oil and gas facilities are governed by more stringent effluent limitations guidelines, new source performance standard, or pretreatment standards, the more stringent effluent limitations guidelines, new source performance standards, or pretreatment standards applicable at the point of discharge shall apply.

4. Subpart D is proposed to be amended by revising §§ 435.40 and 435.41 to read as follows:

Subpart D—Coastal Subcategory

§ 435.40 Applicability; description of the coastal subcategory.

The provisions of this subpart are applicable to those facilities engaged in field exploration, drilling, well production, and well treatment in the oil and gas industry in areas defined as ''coastal.'' The term *coastal* means:

(a) Any oil and gas facility located in or on a water of the United States landward of the territorial seas; or

(b)(1) Oil and gas facilities in existence on April 13, 1979 or thereafter and are located landward from the inner boundary of the territorial seas and bounded on the inland side by the line defined by the inner boundary of the territorial seas eastward of the point defined by 89°45′ W. Longitude and 29°46′ N. Latitude and continuing as follows west of that point:

Direction to west longitude	Direction to north latitude
West, 89°48′	North, 29°50′.
West, 90°12′	North, 30°06′.
West, 90°20′	South, 29°35′.
West, 90°35′	South, 29°30′.
West, 90°43′	South, 29°25′.

Direction to west longitude	Direction to north latitude
West, 90°57′	North, 29°32′.
West, 91°02′	North, 29°40′.
West, 91°14′	South, 29°32′.
West, 91°27′	North, 29°37′.
West, 92°33′	North, 29°46′.
West, 91°46′	North, 29°50′.
West, 91°50′	North, 29°55′.
West, 91°56′	South, 29°50′.
West, 92°10′	South, 29°44′.
West, 92°55′	North, 29°46′.
West, 93°15′	North, 30°14′.
West, 93°49′	South, 30°07′.
West, 94°03′	South, 30°03′.
West, 94°10′	South, 30°00′.
West, 94°20′	South, 29°53′.
West, 95°00′	South, 29°35′.
West, 95°13′	South, 29°28′.
East, 95°08′	South, 29°15′.
West, 95°11′	South, 29°08′.
West, 95°22′	South, 28°56′.
West, 95°30′	South, 28°55′.
West, 95°33′	South, 28°49′.
West, 95°40′	South, 28°47′.
West, 96°42′	South, 28°41′.
East, 96°40′	South, 28°28′.
West, 96°54′	South, 28°20′.
West, 97°03′	South, 28°13′.
West, 97°15′	South, 27°58′.
West, 97°40′	South, 27°45′.
West, 97°46′	South, 27°28′.
West, 97°51′	South, 27°22′.
East, 97°46′	South, 27°14′.
East, 97°30′	South, 26°30′.
East, 97°26′	South, 26°11′.

(2) East to 97°19′ W. Longitude and Southward to the U.S.—Mexican border.

§ 435.41 Specialized definitions.

For the purpose of this subpart:

(a) Except as provided in this section, the general definitions, abbreviations and methods of analysis set forth in 40 CFR part 401 shall apply to this subpart.

(b) The term *average of daily values for 30 consecutive days* is the average of the daily values obtained during any 30 consecutive day period.

(c) The term *Cook Inlet* means all of the production platforms (''existing sources'' or ''existing dischargers'') and exploratory operations (''new dischargers'') addressed by EPA's Region X in the general NPDES permit for Cook Inlet.

(d) The term *daily values* as applied to produced water effluent limitations and NSPS refers to the daily measurements used to assess compliance with the maximum for any one day.

(e) The term *deck drainage* refers to any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas within facilities subject to this subpart.

(f) The term *development facility* means any fixed or mobile structure subject to this subpart that is engaged in the drilling of productive wells.

(g) The term *dewatering effluent* means wastewater from drilling fluids and cuttings dewatering activities (including but not limited to reserve pits or other tanks or vessels, and chemical or mechanical treatment occurring during the drilling solids separation/recycle/disposal process).

(h) The term *diesel oil* refers to the grade of distillate fuel oil, as specified in the American Society for Testing and Materials Standard Specification for Diesel Fuel Oils D975–91, that is typically used as the continuous phase in conventional oil-based drilling fluids. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR Part 51. Copies may be obtained from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103. Copies may be inspected at the Office of the Federal Register, 800 North Capitol Street, N.W., Suite 700, Washington, DC.

(i) The term *domestic waste* refers to materials discharged from sinks, showers, laundries, safety showers, eye-wash stations, hand-wash stations, fish cleaning stations, and galleys located within facilities subject to this subpart.

(j) The term *drill cuttings* refers to the particles generated by drilling into subsurface geologic formations and carried to the surface with the drilling fluid.

(k) The term *drilling fluid* refers to the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-based drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspending medium for solids, whether or not oil is present. An oil-based drilling fluid has diesel oil, mineral oil, or some other oil as its continuous phase with water as the dispersed phase.

(l) The term *exploratory facility* means any fixed or mobile structure subject to this subpart that is engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs.

(m) The term *garbage* means all kinds of victual, domestic, and operational waste, excluding fresh fish and parts thereof, generated during the normal operation of coastal oil and gas facility and liable to be disposed of continuously or periodically, except dishwater, graywater, and those substances that are defined or listed in other Annexes to MARPOL 73/78. MARPOL 73/78 is available from the National Technical Information Service (NTIS) (reference number ADA 183 505), 5285 Port Royal Road, Springfield, VA 22161.

(n) The term *maximum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings means the maximum concentration allowed as measured in any single sample of the barite.

(o) The term *maximum for any one day* as applied to BPT, BCT and BAT effluent limitations and NSPS for oil and grease in produced water means the maximum concentration allowed as measured by the average of four grab samples collected over a 24-hour period that are analyzed separately. Alternatively, for BAT and NSPS the maximum concentration allowed may be determined on the basis of physical composition of the four grab samples prior to a single analysis.

(p) The term *minimum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings means the minimum 96-hour LC50 value allowed as measured in any single sample of the discharged waste stream. The term *minimum* as applied to BPT and BCT effluent limitations and NSPS for sanitary wastes means the minimum concentration value allowed as measured in any single sample of the discharged waste stream.

(q) The term *M9IM* means those coastal facilities continuously manned by nine (9) or fewer persons or only intermittently manned by any number of persons.

(r) The term *M10* means those coastal facilities continuously manned by ten (10) or more persons.

(s)(1) The term *new source* means any facility or activity of this subcategory that meets the definition of ''new source'' under 40 CFR 122.2 and meets the criteria for determination of new sources under 40 CFR 122.29(b) applied consistently with all of the following definitions:

(i) The term *water area* as used in the term ''site'' in 40 CFR 122.29 and 122.2 means the water area and ocean floor beneath any exploratory, development, or production facility where such facility is conducting its exploratory, development or production activities.

(ii) The term *significant site preparation work* as used in 40 CFR 122.29 means the process of surveying, clearing or preparing an area of the ocean floor for the purpose of constructing or placing a development or production facility on or over the site.

(2) ''New Source'' does *not* include facilities covered by an existing NPDES permit immediately prior to the effective date of this subpart pending

EPA issuance of a new source NPDES permit.

(t) The term *no discharge of free oil* means that waste streams may not be discharged when they would cause a film or sheen upon or a discoloration of the surface of the receiving water or fail the static sheen test defined in Appendix 1 to 40 CFR part 435, subpart A.

(u) The term *produced sand* refers to slurried particles used in hydraulic fracturing, the accumulated formation sands and scales particles generated during production. Produced sand also includes desander discharge from the produced water waste stream, and blowdown of the water phase from the produced water treating system.

(v) The term *produced water* refers to the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

(w) The term *production facility* means any fixed or mobile structure subject to this subpart that is either engaged in well completion or used for active recovery of hydrocarbons from producing formations. It includes facilities that are engaged in hydrocarbon fluids separation even if located separately from wellheads.

(x) The term *sanitary waste* refers to human body waste discharged from toilets and urinals located within facilities subject to this subpart.

(y) The term *static sheen test* refers to the standard test procedure that has been developed for this industrial subcategory for the purpose of demonstrating compliance with the requirement of no discharge of free oil. The methodology for performing the static sheen test is presented in appendix 1 to 40 CFR part 435, subpart A.

(z) The term *toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings refers to the bioassay test procedure presented in appendix 2 of 40 CFR part 435, subpart A.

(aa) The term *well completion fluids* refers to salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production.

(bb) The term *well treatment fluids* refers to any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

(cc) The term *workover fluids* refers to salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures.

(dd) The term *96-hour LC50* refers to the concentration (parts per million) or percent of the suspended particulate phase (SPP) from a sample that is lethal to 50 percent of the test organisms exposed to that concentration of the SPP after 96 hours of constant exposure.

5. Section 435.42 is proposed to be amended by revising the introductory text and be in the table to paragraph (a) by adding at the end an entry for ''Produced Sand'' to read as follows:

§ 435.42 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).

Except as provided in 40 CFR 125.30 through 125.32, any existing point source subject to this subpart must achieve the following effluent limitations representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available.

(a) * * *

BPT EFFLUENT LIMITATIONS

Pollutant parameter waste source	Maximum for any 1 day	Average of values for 30 consecutive days shall not exceed	Residual chlorine minimum for any 1 day
* * *	* *	* *	*
Produced Sand	zero discharge	zero discharge	NA

* * * * *

6. Sections 435.43 through 435.47 are proposed to be added to subpart D to read as follows:

§ 435.43 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

Except as provided in 40 CFR 125.30 through 125.32, any existing point source subject to this Subpart must achieve the following effluent limitations representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT):

BAT EFFLUENT LIMITATIONS

Stream	Pollutant parameter	BAT effluent limitations
Produced Water:		
(A) All coastal areas except Cook Inlet		No discharge.
(B) Cook Inlet	Oil & Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l.
Drilling Fluids and Drill Cuttings:		
Option 1:		
(A) All coastal areas except Cook Inlet		No discharge.
(B) Cook Inlet	Free Oil[1]	No discharge.
	Diesel Oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.

BAT EFFLUENT LIMITATIONS—Continued

Stream	Pollutant parameter	BAT effluent limitations
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3 percent by volume.[3]
Option 2:		
(A) All coastal areas except Cook Inlet		No discharge.
(B) Cook Inlet	Free Oil1[1]	No discharge.
	Diesel Oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 10 percent to 100 percent by volume.[3]
Option 3:		
All coastal areas		No discharge.
Well Treatment, Workover and Completion Fluids:		
Option 1:		
(A) All coastal areas except freshwater of Texas and Louisiana.	Free Oil[1]	No discharge.
(B) Freshwaters of Texas and Louisiana		No discharge.
Option 2:		
(A) All coastal areas except Cook Inlet		No discharge.
(B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l.
Produced Sand		No discharge.
Deck Drainage	Free Oil[2]	No discharge.
Domestic Waste	Foam	No discharge.

[1] As determined by the static sheen test
[2] As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
[3] As determined by the toxicity test (see appendix 2 of 40 CFR part 435, subpart A).

§ 435.44 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best conventional pollutant control technology (BCT).

Except as provided in 40 CFR 125.30 through 125.32, any existing point source subject to this subpart must achieve the following effluent limitations representing the degree of effluent reduction attainable by the application of the best conventional pollutant control technology (BCT):

BCT EFFLUENT LIMITATIONS

Stream	Pollutant parameter	BCT effluent limitations
Produced Water (all facilities)	Oil & Grease	The maximum for any one day shall not exceed 72 mg/l and the 30-day average shall not exceed 48 mg/l.
Drilling Fluids and Drill Cuttings:		
All facilities except Cook Inlet		No discharge.
Cook Inlet	Free Oil	No discharge.[1]
Well Treatment, Workover and Completion Fluids.	Free Oil	No discharge.[1]
Produced Sand		No discharge
Deck Drainage	Free Oil	No discharge.[2]
Sanitary Waste:		
Sanitary M10	Residual Chlorine	Minimum of 1 mg/l maintained as close to this concentration as possible.
Sanitary M91M	Floating Solids	No discharge.
Domestic Waste	Floating Solids and garbage.	No discharge of Floating Solids or garbage.[3]

[1] As determined by static sheen test 40 CFR part 435, subpart A, appendix 1.
[2] As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
[3] As defined in 40 CFR 435.41(1).

§ 435.45 Standards of performance for new sources (NSPS).

Any new source subject to this subpart must achieve the following new source performance standards (NSPS):

NSPS EFFLUENT LIMITATIONS

Stream	Pollutant parameter	NSPS/PSNS effluent limitations
Produced Water (all facilities)		No discharge.
Drilling Fluids and Drill Cuttings:		
Option 1:		
(A) All coastal areas except Cook Inlet		No discharge.
(B) Cook Inlet	Free Oil [1]	No discharge.
	Diesel Oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3 percent by volume.[3]
Option 2:		
(A) All coastal areas except Cook Inlet		No discharge.
(B) Cook Inlet	Free Oil [1]	No discharge.
	Diesel Oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 10 percent to 100 percent to 100 percent by volume.[3]
Option 3:		
All coastal areas		No discharge.
Well Treatment, Workover and Completion Fluids:		
Option 1:		
(A) All coastal areas except freshwater of Texas and Louisiana.	Free Oil [1]	No discharge.
(B) Freshwaters of Texas and Louisiana		No discharge.
Option 2:		
(A) All coastal areas except Cook Inlet		No discharge.
(B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l.
Produced Sand		No discharge.
Deck Drainage	Free Oil [2]	No discharge.
Sanitary Waste:		
Sanitary M10	Residual Chlorine	Minimum of 1 mg/l and maintained as close to this concentration as possible.
Sanitary M91M	Floating Solids	No discharge.
Domestic Waste	Floating Solids, Garbage [4] and Foam.	No discharge of floating solids or garbage or foam.

[1] As determined by the static sheen test.
[2] As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
[3] As determined by the toxicity test (see appendix 2 of 40 CFR part 435, subpart A).
[4] As defined in 40 CFR 435.41(1).

§ 435.46 Pretreatment Standards of performance for existing sources (PSES).

Except as provided in 40 CFR 403.7 and 403.13, any existing source with discharges subject to this subpart that introduces pollutants into a publicly owned treatment works must comply with 40 CFR part 403 and by the effective date of this rule achieve the following pretreatment standards for existing sources (PSES).

PSES EFFLUENT LIMITATIONS

Stream	Pollutant parameter	PSES effluent limitations
Produced Water		No discharge.
Drilling Fluids and Drill Cuttings		No discharge.
Well Treatment, Workover and Completion Fluids		No discharge.
Produced Sand		No discharge.
Deck Drainage		No discharge.

§ 435.47 Pretreatment Standards of performance for new sources (PSNS).

Except as provided in 40 CFR 403.7 and 403.13, any new source with discharges subject to this subpart that introduces pollutants into a publicly owned treatment works must comply with 40 CFR part 403 and by the effective date of this rule achieve the following pretreatment standards for new sources (PSNS).

PSNS EFFLUENT LIMITATIONS

Stream	Pollutant parameter	PSNS effluent limitations
Produced Water(all facilities)	....	No discharge.
Drilling fluids and Drill Cuttings	....	No discharge.
Well Treatment, Workover and Completion Fluids	....	No discharge.
Produced Sand	....	No discharge.
Deck Drainage	....	No discharge.

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